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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Revisit Net Energy Metering Tariffs Pursuant to Decision 16-01-044, and to Address Other Issues Related to Net Energy Metering.	Rulemaking 20-08-020 (Filed September 3, 2020)

SIERRA CLUB OPENING BRIEF

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TABLE OF CONTENTS

TABLE OF AUTHORITIES

Cases

Commission Rules

Statutes & Regulations

Commission Decisions

Other Authorities

SUMMARY OF RECOMMENDATIONS

Sierra Club respectfully requests that the California Public Utilities Commission adopt the following recommendations for the non-low-income residential customer class:

1. Transition all existing NEM 1.0 and NEM 2.0 customers to electrification friendly-rates, defined as non-tiered TOU rates with at least a 2:1 differential between summer peak and off-peak hours. NEM is an overlay tariff and Commission precedent is clear that underlying rates for NEM customers are subject to change. The Commission should require existing NEM customers to switch to eligible electrification-friendly rates at five years from interconnection, and provide a storage rebate starting at $0.20/Wh (approximately $3,200 for an average residential system) to NEM 2.0 customers in exchange for switching to the end state of the successor tariff.

2. Adopt a successor tariff that includes the following four elements:

    a. Successor tariff customers should be required to take service under specified electrification-friendly rates for each IOU's service territory. For SCE, this is TOU-D-PRIME, and for PG&E, it should be E-ELEC. SDG&E does not currently have an eligible residential rate, but Sierra Club recommends using a modified version of the TOU-DER rate that the Joint IOUs have proposed, with the monthly fixed charge reduced to a range similar to PG&E and SCE's eligible rates' fixed charges, and volumetric charges increased accordingly.

    b. The successor tariff should have a net billing structure with export compensation decreasing over time on a glide path from 2021 retail rates to avoided costs. A glide path is necessary to reduce non-participant impacts by reducing customer-generators' export compensation while avoiding market shock. Sierra Club proposes reducing export compensation in tranches, with each successive tranche triggered by installed capacity benchmarks of 1 GW each. Customers in each tranche would have export compensation locked in for 20 years. Export compensation for each tranche would decrease from the 2021 retail rate values toward avoided costs in 10% steps, reaching avoided cost compensation for the final tranche.

c. The Commission should require successor tariff customers to pay non-bypassable charges on gross consumption, including behind-the-meter consumption, rather than assessing NBCs only on exports.

d. Successor tariff customers should be allowed to size their rooftop solar systems to meet their household's projected load if fully electrified with two electric vehicles. This policy promotes electrification for successor tariff customers and advances the state's building decarbonization goals. To the extent that such systems overproduce before the customer electrifies their home, Sierra Club proposes that all net surplus compensation due to the oversized system be collected to fund low-income programs.

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Pursuant to Rule 13.12 of the California Public Utilities Commission ("CPUC" or "Commission") Rules of Practice and Procedure and the oral ruling of Administrative Law Judge ("ALJ") Kelly A. Hymes at the conclusion of evidentiary hearings on August 10, 2021, Sierra Club timely files this Opening Brief on Issues 2 through 6 in the November 19, 2020 Joint Assigned Commission's Scoping Memo and ALJ Ruling Directing Comments on Proposed Guiding Principles ("Scoping Memo"). This Opening Brief is limited to responding to Scoping Memo Issues 2 through 6 as applied to existing net energy metering ("NEM") and successor tariff general market residential customers. The application of Issues 2 through 6 for low-income residential customers is addressed in a separate opening brief filed jointly with GRID Alternatives and Vote Solar.

I. INTRODUCTION

This proceeding provides the Commission the opportunity to review the NEM program holistically and make adjustments that best ensure sustainable growth of rooftop solar in a manner that minimizes rate impacts to non-participants and advances deeper decarbonization by incentivizing adoption of electrification and load-shifting technologies. To achieve these objectives, the Commission should adopt Sierra Club's proposed electrification-oriented successor tariff that provides a glide path to export compensation at avoided cost. The Commission should also move existing non-low-income NEM customers to electrification rates five years from interconnection of their systems and offer NEM 2.0 customers an approximately $3,200 average incentive to deploy battery storage in exchange for moving to the successor tariff end-state. Transitioning existing non-low-income NEM customers to electrification rates is consistent with repeated Commission decisions holding that the underlying rate structures of NEM customers are subject to changes. This transition also advances climate and equity objectives while continuing to maintain substantial system value for NEM customers. Sierra Club's proposals for existing and successor tariff customers collectively reorient the NEM program to meet the demands of the climate crisis through the widespread electrification necessary to end reliance on fossil fuels and its supporting infrastructure.

The Commission should adopt a successor tariff with four key elements: 1) enrollment in an electrification-friendly rate with a fixed charge component; 2) a glide path to export compensation at avoided cost; 3) contributions to non-bypassable charges ("NBCs") based off gross energy consumption; and 4) system sizing to account for a fully electrified household with any annual net surplus compensation ("NSC") funding low-income clean energy programs. Enrollment in electrification rates with a fixed charge component such as Southern California Edison's ("SCE'") TOU-D-PRIME and Pacific Gas & Electric's ("PG&E") agreed upon E-ELEC rate provides multiple benefits and should be the foundation of the successor tariff. The cost-based structure of electrification rates reduces non-participant impacts, discourages energy use during peak demand periods when grid emissions are highest, and encourages the adoption of electrification technologies by increasing their operational cost savings compared with fossil fueled alternatives.

Sierra Club supports a successor tariff that ultimately compensates exports at short-run avoided cost values as determined by the Commission's avoided cost calculator ("ACC"). However, because avoided costs are substantially lower than retail rates, the Commission must provide a glide path to avoided cost export compensation to avoid the market shock that would result from a single drastic and abrupt change in export value. States that have gradually reduced export compensation from retail rates through orderly and predictable step-downs have succeeded in maintaining deployment of customer-sited generation while those that made immediate and substantial cuts to rooftop solar compensation triggered industry layoffs and sharp declines in rooftop solar deployment.[1] Sierra Club proposes one potential glide path that would use a net billing arrangement to first lock-in exports at each IOU's electrification rate and incrementally reach avoided cost through ten 1 GW capacity-based step-downs that account for all deployment under the successor tariff to match the total level of additional customer-sited solar necessary to achieve 2030 targets under Senate Bill ("SB") 100.

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[1] *See* Section II.C.2.(a).

Sierra Club's successor tariff proposal did not initially include changes to how NBCs are incurred by customer-generators, which under NEM 2.0 are charged on imported energy only. However, Sierra Club agrees that successor tariff customers should pay NBCs on gross consumption given the broader societal purpose of the costs embedded in NBCs, such as funding wildfire liability costs and public purpose programs. Together with the fixed charge component of the underlying electrification rate to which successor tariff customers must subscribe, this is the appropriate level of charges the Commission should impose under the successor tariff. Layering on an additional, unavoidable "grid benefits charge" ("GBC") would substantially erode the value proposition of customer-sited resources and chill deployment and corresponding grid benefits of load shifting technologies like battery storage.

With regard to existing NEM customers, while the Commission has identified electrification of homes with solar as a high opportunity area, or "low hanging fruit," in decarbonizing California's buildings,[2] the vast majority of existing residential NEM customers are either on tiered rates or poorly differentiated time-of-use ("TOU") rates that are neither sufficiently optimized to encourage electrification nor correlated with the substantially higher marginal cost of evening electricity. To both further California's decarbonization objectives and reduce non-participant NEM impacts, the Commission should move residential NEM 1.0 and NEM 2.0 customers to electrification-friendly rates, defined as TOU rates with at least a 2:1 differential between summer peak evening and summer weekday off-peak periods. Sierra Club conferred with the parties who submitted Joint Recommendations and takes this position consistent with the Joint Parties, with a modification to expand an exemption from California Alternate Rates for Energy ("CARE") / Family Electric Rate Assistance Program ("FERA") to all low-income NEM customers.[3] Undisputed analysis by Sierra Club Witness Dr. Erin Camp

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[2] Exh. SCL-01, Direct Testimony of M. Vespa at 2:1–2 (citing California Energy Commission ("CEC"), *Session 2 Presentation – IEPR Commissioner Workshop on Building Decarbonization – Building Decarbonization & the CPUC*, at Slide 10 (May 25, 2021), https://www.energy.ca.gov/event/webinar/2021-05/session-2-iepr-commissioner-workshop-building-decarbonization-national).

[3] Sierra Club defines low-income NEM customers as those with "household incomes below 80 percent of the area median income" as set forth in the Commission's Environmental and Social Justice Action Plan. CPUC, *Environmental and Social Justice Action Plan*, at 10, fn. 6 (Feb. 21, 2019), https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/Infrastructure/DC/Env%20and%20Social%20Justice%20ActionPlan_%202019-02-21.docx.pdf. Sierra Club does not support changes to existing NEM customers beyond the proposed rate change and storage incentive for NEM 2.0 customers.

demonstrates that moving NEM customers to electrification-friendly rates encourages electrification by reducing operational costs of electric appliances and vehicles compared to fossil-fueled alternatives while still preserving substantial bill savings for NEM customers and providing the opportunity to increase overall fuel cost savings though adoption of electrification technologies.[4] As detailed in the Joint Recommendations, the transition to electrification rates would be accompanied by marketing and outreach materials that "shall include information on technologies and available incentives that can improve system value such as heat pump water and space heaters, electric vehicles, and batteries" as well as the climate benefits from their adoption and from reducing evening energy usage. With over 1 million existing residential NEM customers, moving NEM customers to electrification rates coupled with outreach on the benefits of fuel switching from fossil fueled to electric technologies is a simple and necessary policy intervention that will meaningfully advance California's climate objectives.

By ensuring that successor tariff customers are enrolled in cost-based rates that encourage electrification, fully funding societal programs through NBCs on gross consumption, and reaching an end state of avoided cost compensation for exports, with costs of a glidepath to non-participants offset by transitioning existing NEM customers to electrification rates, Sierra Club's proposal aligns with the Commission's successor tariff Guiding Principles and properly navigates the statutory directives to ensure "customer-sited renewable generation continues to grow sustainably" while also ensuring total benefits "are approximately equal to the total costs."[5] The Commission should therefore adopt the elements of Sierra Club's successor tariff proposal and transition existing non-low-income NEM customers to electrification rates.

II. DISCUSSION: RESPONSE TO SCOPING MEMO ISSUES TWO THROUGH SIX

A. Scoping Memo Issue 2: What information from the Net Energy Metering 2.0 Lookback Study should inform the successor and how should the Commission apply those findings in its consideration?

Sierra Club has identified the following information from the Lookback Study that the Commission should apply in informing successor tariff design:

[4] *See generally* Exh. SCL-02, Direct Testimony of E. Camp.
[5] Pub. Util. Code § 2827.1(b).

1. Marginal Customer Cost Recovery Through an Electrification Rate with a Fixed Charge Component.

The Lookback Study identifies marginal customer costs ("MCC") for each utility, defined as "costs associated with various customer costs, including but not limited to the customer's transformer, conductors, meter, and billing processing."[6] For PG&E residential customers, the MCC is $156/year, for SCE residential customers the MCC is $124/year, and for SDG&E customers the MCC is $152/year.[7] The Commission should apply these findings by requiring successor tariff customers to enroll in electrification rates with a fixed charge component. PG&E's proposed E-ELEC rate has a monthly fixed charge of $15, or annual fixed cost recovery of $180, and SCE's TOU-D-PRIME rate has a monthly fixed charge of $12, or annual cost recovery of $144. In addition to providing more accurate cost-based TOU signals and incentivizing electrification, requiring successor tariff customers to enroll in these rates as a condition of taking service under the successor tariff ensures MCC recovery. SDG&E does not currently have an eligible electrification rate with a fixed charge component but the Commission has directed it to propose an electrification rate by no later than September 1, 2021.[8] As an interim or alternative rate, Sierra Club recommends the Commission modify the DG-ST rate SDG&E has proposed in this proceeding by reducing the customer charge by $10 from $24.10 to $14.10 with a corresponding increase in volumetric rates. A $14 fixed charge is more consistent with MCC recovery and the fixed charges approved or agreed to in PG&E and SCE's electrification rates.[9]

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[6] Verdant Associates, *Net-Energy Metering 2.0 Lookback Study*, at 52 (Jan. 21, 2021) ("NEM 2.0 Lookback Study"), https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/net-energy-metering-nem/nemrevisit/nem-2_lookback_study.pdf.
[7] *Id*. at 52–55.
[8] D. ("Decision") 20-03-003, *Decision Addressing Proposed Fixed Charge for Residential Customers*, at 42 (Mar. 19, 2020) ("D.20-03-003"), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M329/K839/329839373.PDF; D.21-07-010, *Decision Adopting Settlement Agreement to Update Marginal Costs, Cost Allocation and Electric Rate Design for San Diego Gas & Electric Company; Ordering a Separate Application for a Real-Time Pricing Dynamic Rate Pilot; Rejecting Schools-Only Class Proposal; and Modifying Decision 12-12-004*, at 32 (July 16, 2021) ("SDG&E will hold workshops to consider design of an optional un-tiered residential TOU rate with a fixed charge and will file an application for a proposed un-tiered rate no later than September 1, 2021.") ("D.21-07-010"), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M393/K302/393302635.PDF.
[9] Exh. SCL-01, Direct Testimony of M. Vespa, at 18–19. *See also* D.20-03-003 at 42 (directed SDG&E to develop an electrification rate "*similar to* the TOU-D-PRIME rate") (emphasis added).

2. The Lookback Study Cost-Effectiveness Results and Impact of the Transition from NEM 1.0 to NEM 2.0 on Residential Solar Deployment Supports a Glidepath to Avoided Cost Compensation.

For residential solar customers, the Lookback Study identifies Total Resource Cost ("TRC") and Ratepayer Impact Measure ("RIM") test results as under 1.0 and Participant Cost Test ("PCT") results as above 1.5 for SCE, above 1.75 for PG&E and above 2.0 for SDG&E.[10] The cost-effectiveness results in the Lookback Study support transitioning away from retail-rate compensation for exports in the successor tariff to export compensation at avoided cost. However, the level of installed capacity, which dropped the year NEM 2.0 was adopted and gradually increased back to previous levels, is also important to consider.[11] This information supports a gradual transition toward avoided cost compensation to give customer-sited generation providers time to adjust to decreased export compensation and a new tariff structure. Moreover, the transition from NEM 1.0 to NEM 2.0 was a one-time, relatively minor adjustment, given the lack of differentiation in default TOU rates. In contrast, reducing export compensation to avoided cost represents a drastic reduction in bill savings. Contemplated successor tariff changes are much more significant than those from NEM 1.0 to NEM 2.0 and should be implemented gradually.

3. The Lookback Study Cost-Effectiveness Results Support Moving Existing NEM Customers to Electrification-Friendly Rates.

Commission precedent is clear that underlying rate structures for NEM customers are subject to change.[12] The Commission should apply the Lookback Study findings on cost-effectiveness for residential NEM customers by moving NEM 1.0 and NEM 2.0 customers to more differentiated electrification-friendly rates five years from interconnection to reduce non-participant impacts and better align export compensation with its grid value at different times of day.

B. Scoping Memo Issue 3: What method should the Commission use to analyze the program elements identified in Issue 4 and the resulting proposals, while ensuring the proposals comply with the guiding principles?

Program elements should be viewed collectively to achieve a successor tariff that

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[10] NEM 2.0 Lookback Study at 80–81.
[11] *Id.* at 3.
[12] *See* Section II.E.2.

encourages electrification, provides certainty for prospective solar customers, sustains the deployment of customer-sited renewables at a rate that aligns with the State's SB 100 planning, and gives the solar industry a glide path to an end state that minimizes non-participant impacts. The following methods can be used to assist in reaching this determination:

Payback periods that properly account for total system cost: Payback periods can be a metric for assessing the extent to which a successor tariff proposal ensures customer-sited distributed generation continues to grow sustainably, as required under Public Utilities Code Section 2827.1(b)(1). Sierra Club shares concerns of other parties with reliance on estimated payback periods in the E3 analysis of Cost-effectiveness of NEM Successor Rate Proposals due to its use of solar costs from NREL's Annual Technology Baseline ("ATB") report, which is substantially below actual data on installed costs due to its exclusion of costs such as developer profits, developer fees, and financing fees.[13]

Total Resource Cost Test results: The Commission's *Decision Adopting Guiding Principles for the Development of a Successor to the Current Net Energy Metering Tariff* ("Guiding Principles Decision") affirmed the primacy of Total Resource Cost ("TRC") test to review distributed energy resource programs, with the Program Administrator Cost ("PCT") test and Ratepayer Impact Measure ("RIM") as secondary considerations.[14]

Avoided Cost Calculator Values: The majority of parties have looked to the ACC as the basis from which to value export compensation. The extent to which the successor tariff end state values exports at avoided cost is a method to assess program elements.

Societal Benefits: Public Utilities Code Section 2827.1(b)(4) requires the Commission to ensure that "the total benefits" of the successor tariff "to all customers and the electric system are approximately equal to the total costs." Societal benefits are benefits that flow to all customers. Even where they cannot reasonably be quantified, they should factor into the Commission's ultimate determination on successor tariff design. For example, because ACC values exclude societal benefits, the extent to which a successor

[13] *See, e.g.*, Exh. ASO-01, Direct Testimony of A. Gong at 5:4–6.
[14] D.21-02-007, *Decision Adopting Guiding Principles for the Development of a Successor to the Current Net Energy Metering Tariff*, at 7 (Feb. 17, 2021) ("D.21-02-007"), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M366/K418/366418635.PDF.

tariff proposal values export compensation at avoided cost militates against imposition of fees levied only upon successor tariff customers.

Changes to Existing NEM Customers: To the extent a successor tariff decision includes reforms for existing NEM customers, such as through a transition to electrification rates, these changes should inform the non-participant impacts of a glide path component to the successor tariff.

C. Scoping Memo Issue 4: What program elements or specific features should the Commission include in a successor to the current net energy metering tariff?

Program elements that should be included in a successor tariff are:

1) Required enrollment in an electrification-friendly rate with a fixed charge component;
2) Net billing with long-term predictability in export compensation with capacity-based step-downs to export compensation at short-run avoided cost;
3) Non-bypassable charges based on gross electricity consumption; and
4) System sizing to meet needs of fully electrified households, with any NSC directed to fund low-income clean energy programs.

Program elements that should not be included in a successor tariff include a grid benefits charge, TOU netting, and unpredictable export compensation.

1. Element 1: Enrollment in Electrification Rates with a Fixed Charge Component.

The foundational element of the successor tariff should be required enrollment in an electrification rate with a fixed charge component. Required enrollment in electrification rates provides numerous benefits that further the successor tariff Guiding Principles. First, their "cost-based nature inherently reduces the cost shift associated with solar adoption through more appropriate time-variant pricing" thereby improving equity among customers pursuant to Guiding Principle (b).[15] Second, high summer peak to off-peak differentials discourage energy use during peak periods when the carbon intensity of grid emissions is highest, resulting in GHG and system reliability benefits pursuant to Guiding Principles (e) and (g). Third, electrification

[15] Exh. IOU-01, Joint IOU Direct Testimony at 120:14–15 (describing SCE's TOU-D-PRIME electrification rate).

rates increase the operational cost savings of building and transportation electrification technologies and thereby incentivize their adoption with corresponding air quality and climate benefits from reduced fossil fuel dependency pursuant to Guiding Principle (e).

As the Joint Investor Owned Utilities ("Joint IOUs") observe, "[t]here is broad consensus that the Reform Tariff should generally: require residential customers to take service on cost-based TOU rates that better align price signals with grid needs, maximize benefits to all ratepayers, and further the state's electrification and GHG reduction goals."[16] Indeed, this is one of the few areas where the solar parties and IOUs largely agree.[17] Where the disagreement exists is the specific rates successor tariff customers should have the option of enrolling in. Sierra Club recommends adopted or agreed upon electrification rates with a fixed charge. For PG&E, this rate is E-ELEC, and for SCE, this rate is TOU-D-PRIME. SDG&E does not currently have an approved or agreed upon qualifying rate but has been directed to propose an electrification rate by September 1, 2021. Until such time as an eligible rate is adopted, Sierra Club recommends modifying the DG-ST rate SDG&E proposed in this proceeding to reduce the fixed charge by $10 to $14.10 consistent with the fixed charges in E-ELEC and TOU-D-PRIME.

a) Electrification rates are cost-based and further equity among customers.

As the Joint IOUs acknowledge, "[t]he current residential default tiered TOU rate structures are not cost based."[18] Unlike current default TOU rates, electrification rates align with the high marginal cost of summer evening electricity due to higher peak to off peak ("POP") differentials between summer mid-day and evening TOU periods. For example, the pending settlement on residential rates in PG&E's GRC's Phase 2 proceeding found that E-ELEC, PG&E's proposed electrification rate, provides "TOU rate differentials that are close to PG&E's estimated marginal cost targets."[19] The summer POP differential for E-ELEC is over 2:1, or close to $0.22/kWh.[20] In contrast, the summer POP differential for TOU-C, PG&E's default

[16] Exh. IOU-02, Joint IOU Rebuttal Testimony at 44:12–14.
[17] *Compare* Exh. SVS-03, Direct Testimony of T. Beach at ii ("customers of PG&E and SDG&E would be required to take service from one of the utility's available untiered time-of-use (TOU) rates designed to promote beneficial electrification.") *with* Exh. IOU-1, Joint IOU Direct Testimony at 106:2–3 (proposing to require enrollment on rates with cost-based, non-tiered TOU differentials and fixed charges).
[18] *Id.* at 44:14–15.
[19] Exh. SCL-04, Mtn. of PG&E for Adoption of Residential Rate Design Supplemental Settlement Agreement, at 9 (Mar. 29, 2021).
[20] *Id.* at Attach. A at 12; Exh. SCL-01, Direct Testimony of M. Vespa at 17:11.

TOU rate, is 1.2:1, or slightly over $0.06/kWh.[21] Similarly, SCE's electrification rate, TOU-D-PRIME, has a 2.6:1 POP differential which "inherently reduces the cost-shift associated with solar adoption through more appropriate time-variant pricing."[22] In analyzing the bill impact of moving customers from default TOU rates to E-ELEC in PG&E service territory and to TOU-D-PRIME in SCE service territory, Dr. Camp found a 19 to 22 percent reduction in bill savings absent adoption of electrification technologies.[23] This finding is consistent with that of the Joint IOUs, which determined that adoption of a cost-based rate for NEM successor tariff customers reduces non-participant impacts by twenty-two percent.[24] Cost-based rates are the logical starting point for a successor tariff that furthers equity among customers by meaningfully reducing non-participant impacts.

b) Electrification rates discourage energy use during peak periods when the carbon intensity of grid emissions is highest, resulting in GHG and system reliability benefits pursuant to Guiding Principles (e) and (g).

Electrification rates discourage energy during peak periods because of their high summer on-peak prices,[25] thereby providing grid reliability benefits by reducing peak demand and maximizing benefits to all customers. This price signal is not as strong for poorly differentiated TOU rates such as PG&E's default TOU rate.[26] Evening hours are also when grid emissions are highest. As shown below in the California Independent System Operator's ("CAISO") analysis of grid emissions, greenhouse gas ("GHG") emissions from energy use in the middle of the day are now lower than in the middle of the night, with evening energy use in summer months having the highest greenhouse gas intensity.[27]

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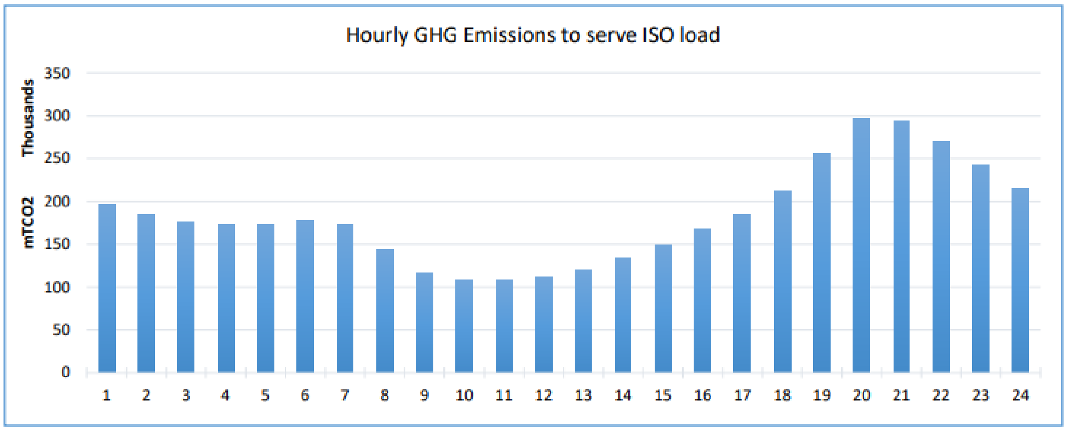
[21] Exh. SCL-04, Mtn. of PG&E for Adoption of Residential Rate Design Supplemental Settlement Agreement, Attach. A at 10–11; Exh. SCL-01, Direct Testimony of M. Vespa at 9:23–24.
[22] Exh. IOU-01, Joint IOU Direct Testimony at 120:14–16.
[23] Exh. SCL-02, Direct Testimony of Dr. Camp at 19:18, 23:1.
[24] Exh. IOU-01, Joint IOU Direct Testimony at 101, Figure IV-29.
[25] *See, e.g.*, Tr. Vol. 11 at 2019:8–14 (B. Gutierrez/N. Chau, PAO).
[26] *Id.*
[27] Exh. SCL-01, Direct Testimony of M. Vespa at 16 (citing CAISO, *Greenhouse Gas Emission Tracking Report* (July 2020), http://www.caiso.com/Documents/GreenhouseGasEmissions-TrackingReport-Jul2020.pdf).

FIGURE 3 – Total hourly GHG emissions to serve ISO load. This figure reflects the hourly sum of GHG emissions from internal ISO dispatches and GHG emissions from imports serving ISO load for the month of July 2020.



The cost-based price signals of electrification rates like SCE's TOU-D-PRIME function to "discourage usage during high GHG production periods and encourage usage in periods where there are fewer GHG producing resources online."[28] It is both reasonable and necessary to condition successor tariff participation on enrollment in a rate with a strong, cost-based price signal to reduce energy use during summer evening periods when the demands on the grid and GHG emissions are at their peak.[29]

c) Electrification rates incentivize the adoption of building and transportation electrification technologies by increasing operational cost savings with corresponding air quality and climate benefits from reduced fossil fuel dependency pursuant to Guiding Principle (e).

By providing lower cost-based rates in off-peak periods, electrification rates allow customers to "affordably adopt new building electrification (BE) and transportation electrification (TE) technologies."[30] Compared to default TOU rates, electrification rates like E-ELEC and TOU-D-PRIME provide an incentive for solar customers to electrify their homes and vehicles by significantly increasing bill savings from adoption of electrification technologies.[31] For example, analyzing bill impacts of a NEM solar customer in Northern Los Angeles on SCE's

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[28] Exh. IOU-01, Direct Joint IOU Testimony at 120:7–10.

[29] Low-income customers tend to face a higher energy burden than their non-low-income counterparts and may face barriers to responding effectively to these price signals. Sierra Club recommends that the Commission consider exempting low-income customers from a requirement through an equity proposal, as detailed in the joint brief filed with GRID Alternatives and Vote Solar.

[30] Exh. IOU-01, Direct Joint IOU Testimony at 120:11–12.

[31] Exh. SCL-02, Direct Testimony of Dr. Camp at 3:17–19.

default TOU rate compared to a customer on TOU-D-PRIME, Sierra Club witness Dr. Camp found that enrollment in TOU-D-PRIME resulted in over $500 in annual fuel cost savings from adoption of an electric vehicle and over $225 from adoption of a heat pump water heater.[32] Adoption of electrification technologies comes with significant greenhouse gas benefits, with a fully electrified home and electric vehicle reducing household greenhouse gas pollution by 59 to 78 percent.[33] On top of the climate benefits, the California Air Resources Board has recognized that "100 percent electrification of natural gas appliances in California would result in substantial public health benefits."[34] Accordingly, because electrification is "a key pillar of California's decarbonization strategy,"[35] the Commission should ensure a successor tariff is designed to further widespread electrification. Electrification of California's existing building stock will be challenging. Requiring successor tariff customers to enroll in an electrification rate is a simple and effective component that will advance electrification by providing bill savings when customers switch from polluting combustion-based technologies to zero emissions alternatives.

d) Eligible successor tariff electrification rates for each IOU.

The Commission should require successor tariff customers in SCE service territory to enroll in TOU-D-PRIME as recommended by the Joint IOUs.[36] TOU-D-PRIME is a highly differentiated, cost-based, approved rate with a $12 fixed charge. This rate provides a significantly greater incentive to electrify than SCE's default TOU rate, with solar customers reducing overall energy bills by over $800 annually through home and vehicle electrification compared to the default TOU rate.[37]

The Commission should require successor tariff customers in PG&E service territory to enroll in the proposed E-ELEC rate. E-ELEC is an electrification rate with a fixed charge that was reduced from $25 to $15 in an uncontested settlement currently pending Commission

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[32] *Id.* at 22:1.
[33] *Id.* at 3:15–16.
[34] *Id.* at 5:10–18 (*citing* California Air Resources Board ("CARB"), *Resolution 20-32*, (Nov. 19, 2020), https://ww3.arb.ca.gov/board/res/2020/res20-32.pdf).
[35] *Id.* at 6:4–5 (*citing* CPUC, *Alternative Ratemaking Mechanisms for Distributed Generation Resources in California*, at 25–26 (Jan. 28, 2021) ("Successor Tariff White Paper"), https://www.ethree.com/wp-content/uploads/2021/02/Alternative-Ratemaking-Mechanisms-for-Distributed-Energy-Resources-in-California-Successor-Tariff-Options-Compliant-with-AB-327-1.pdf.
[36] Exh. IOU-01, Direct Joint IOU Testimony at 120–123.
[37] Exh. SCL-02, Direct Testimony of Dr. Camp at 20:18–21:1.

approval in Phase 2 of PG&E's General Rate Case ("GRC").[38] In this proceeding, PG&E has proposed a new rate, E-DER, with a $20 fixed charge and a close to 2:1 differential between summer peak and off-peak periods, less than the differential in E-ELEC.[39] As the product of robust stakeholder process and input resulting in an uncontested settlement agreement in the GRC proceeding, the Commission should adopt E-ELEC as the qualifying rate for successor tariff customers. To the extent the Commission is inclined to adopt PG&E's proposed E-DER rate, it should do so as an optional rate open to all customers with distributed energy resources ("DERs").[40]

SDG&E currently does not have an adopted or agreed upon electrification rate. However, in D.20-03-003, the Commission directed SDG&E to propose an un-tiered residential TOU rate with a fixed charge component to facilitate residential electrification, with the Commission later directing that this rate be proposed no later than September 1, 2021.[41] To the extent this rate is not approved by the time a successor tariff is implemented, as an interim or alternative rate, successor tariff customers could use the TOU-DER rate SDG&E has proposed in this proceeding, modified to reduce the fixed charge by $10 from $24.10 to $14.10.[42] A $14 fixed charge is consistent with the fixed charges approved or agreed upon for PG&E and SCE electrification rates. To the extent SDG&E believes a higher fixed charge is warranted for its electrification rate, its forthcoming application for approval of an electrification rate is the appropriate venue, given its singular focus on rate design.

While rates can evolve over time, electrification rates are "much, much closer to marginal

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[38] Exh. SCL-04, Mtn. of PG&E for Adoption of Residential Rate Design Supplemental Settlement Agreement at 8.

[39] Exh. IOU-01, Direct Joint IOU Testimony at 113. The proposed E-DER rate has an $0.18 kWh POP differential. The POP differential under E-ELEC is close to $0.22 kWh. Exh. SCL-04, Attach. 1 at 12.

[40] As noted by the Solar Energy Industries Association ("SEIA") and Vote Solar, use of agreed upon or adopted electrification rates provides "a common rate platform for all types of DERs, and would take a major step toward reducing the impacts of distributed solar on non-participants." Exh. SVS-04, Rebuttal Testimony of T. Beach, at iii. Were IOU proposed rates the only option for successor tariff customers, it would "discriminate against adoption of one particular DER – solar – by requiring customers who adopt solar to use a rate with higher fixed charges that differs significantly from the rate available to those who adopt other types of DERs." *Id.*

[41] D.20-03-003 at 42; D.21-07-010 at 32.

[42] Exh. IOU-01, Direct Joint IOU Testimony at 116. Reducing the fixed charge $10 would increase volumetric rates of each TOU period by $0.026/kWH. Exh. SCL-01, Direct Testimony of M. Vespa at 19:11–12.

costs than default time-of-use rates."[43] Since these rates are close to marginal cost today, significant change is unlikely to occur.[44] The electrification rates Sierra Club proposes successor tariff customers enroll in therefore provide a stable underpinning for the future tariff. To the extent TOU periods shift over time, consistent with established Commission policy, successor tariff customers would have the right to maintain their existing TOU rate for five years.[45]

e) The Commission should not adopt proposals that would allow successor tariff customers to enroll in any available TOU rate.

Proposals to allow successor tariff customers to take service under any applicable TOU rate are unpersuasive. For example, the Public Advocates Office ("Cal Advocates") simultaneously states that "[s]uccessor tariff rates for consumption and exports must reflect accurate, cost-based groupings of underlying marginal costs and current grid conditions and TOU rates that align closer to costs will maximize benefits to all ratepayers" while permitting successor tariff customers to enroll in poorly differentiated rates that are misaligned aligned with grid costs.[46] As Cal Advocates admits, PG&E's default TOU rate, TOU-C, is not as well aligned with costs as E-ELEC.[47] Its inclusion as an eligible rate in Cal Advocates' successor tariff proposal therefore fails to "maximize the value of customer-sited renewable generation to all customers" in accordance with Guiding Principle (g).[48] Cal Advocates also acknowledges that E-ELEC's higher differential between summer on- and off-peak prices provides more of an incentive to reduce or avoid energy usage during peak periods, and therefore unlike TOU-C, maximizes value to the electrical system in accordance with Guiding Principle (g).[49] Cal Advocates' reliance on past Commission guidance on TOU rates in D.17-01-006 as support for successor tariff customer choice of TOU rates is misplaced.[50] D.17-01-006 provided guidance on the introduction of TOU rates to the general market where customer choice was important for

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[43] Tr. Vol. 8 at 1302:11–14 (T. Beach, SEIA/Vote Solar).
[44] *Id.* at 1302:15–20 (T. Beach, SEIA/Vote Solar).
[45] D.17-01-006, *Decision Adopting Policy Guidelines to Assess Time Periods for Future Time-of-use Rates and Energy Resource Contract Payments*, at 74 (Jan. 23, 2017) ("D.17-01-006"), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M172/K782/172782737.PDF.
[46] Exh. PAO-01, Cal Advocates Direct Testimony at 3:14:9–11.
[47] Tr. Vol. 11 at 2012:7–11, 2013:22–27 (B. Gutierrez/N. Chau, PAO).
[48] D.21-02-007 at 34.
[49] *Id.* at 2019:8–14 (B. Gutierrez/N. Chau, PAO).
[50] Exh. PAO-01, Cal Advocates Direct Testimony at 3-14:1–2.

customer acceptance of a rate design residential customers were not familiar with.[51] Nothing in D.17-01-006 can legitimately be read to dictate the design of the successor tariff. To the contrary, allowing a successor tariff customer to enroll in poorly differentiated TOU rates conflicts with multiple Guiding Principles for this proceeding. Moreover, unlike Cal Advocates' proposed GBC, which successor tariff customers cannot avoid and have no choice but to accept, limiting enrollment to electrification rates still provides successor tariff customers with a range of choices to maximize system value, from measures as simple as precooling their home to limit peak energy usage to adopting electrification technologies to take advantage of lower off-peak rates and corresponding bill savings. In designing the successor tariff, the Commission must look forward to an electrified future where peak energy use is discouraged. Electrification rates are a fundamental part of achieving that future and should be the foundation of the successor tariff.

2. Element 2: Glide Path to Export Compensation at Avoided Cost.

To properly balance the statutory directive that a successor tariff ensure "customer-sited renewable distributed generation continues to grow sustainably" with a tariff that ensures total benefits "to all customers and the electrical system are approximately equal to the total costs,"[52] the Commission should create a glide path where export compensation reaches avoided cost though capacity-based step-downs. While the Commission declined to define "grow sustainably" in the Guiding Principles Decision, this phrase cannot be legitimately construed as allowing the type of immediate and severe cuts to compensation for customer-sited renewable generation that occurred in Nevada and Hawaii and resulted in precipitous drops in deployment. A glide path with gradual step-downs in export compensation has been successfully applied in other jurisdictions and balances the requirements of Section 2827.1.

Sierra Club's proposed glide path would: 1) use a net billing approach that locks in export compensation for 20 years with no escalation; 2) first set export compensation at each IOU's qualifying electrification rate with 1 GW step-downs reducing export compensation ten percent from the 2021 rate to short-run avoided cost, where avoided cost is reached after 10 GW of total deployment that accounts for all customer-sited generation enrolled in the successor

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[51] *See* D.17-01-006 at 39 (noting support for "a menu-based approach giving customers choice as a means of promoting customer acceptance.").
[52] Pub. Util. Code § 2827.1(b)(1), (b)(4).

tariff. This is one possible approach, and Sierra Club acknowledges there are other reasonable glide paths. What is important is that the structure gives the market the opportunity to adjust to declining export compensation and that export compensation is locked in for a sufficient period to provide long-term certainty.

a) The record demonstrates that a glide path is needed to avoid market shock and ensure customer-sited renewable generation continues to grow sustainably.

A glide path that gradually decreases export compensation to avoided cost will allow the necessary NEM reforms to move forward without creating market shock that would undermine the sustainable growth of customer-sited distributed solar. Conversely, an immediate shift to avoided cost export compensation without a glide path is likely to result in "an immediate disruption in installations as the economics to install distributed solar would drop, followed by an uncertain recovery dependent on future changes to the ACC."[53] Surveying the results in other states that have adopted changes to net metering demonstrates that "in general, solar installations remain stable when utilities provide a stepdown of the export rate in a net billing scheme, and collapse if no glidepath is offered."[54]

(1) The Joint IOUs overgeneralize NEM reforms enacted in other states and misstate the impacts to the solar industry.

Parties that propose an immediate switch to avoided cost export compensation have overstated the ability of the rooftop solar market to absorb the resulting market shock based on net metering reforms in other states that are not comparable to what the parties propose here. For example, the Joint IOUs suggest that reforms in Arizona, Hawaii, Nevada, New York, and South Carolina are instructive.[55] However, when questioned about how their successor tariff proposal—which contains avoided cost export compensation, instantaneous netting within TOU periods, and an annual grid access charge ranging from approximately $10 to $14/kW—would compare to the reforms adopted in those states, Joint IOU Witness Tierney conceded that among the other reform structures the Joint IOUs cited, "[n]one of them have all of those elements."[56]

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[53] Exh. ASO-01, Direct Testimony of A. Gong at 14:3–5.
[54] Exh. ASO-02, Rebuttal Testimony of A. Gong at 8:26–9:2.
[55] *See* Exh. IOU-01, Joint IOU Direct Testimony at 31:15–32:2.
[56] Tr. Vol. 1 at 130:6–7 (S. Tierney, Joint IOUs).

While many of these programs contained some of the proposed elements present in the proposals of the Joint IOUs, Cal Advocates, and Natural Resources Defense Council ("NRDC"), none of them are truly helpful points of reference, not only because they lack California's unique context, but also because they are simply not comparable programs.

Additionally, the Joint IOUs have mistakenly relied on the continued growth of rooftop solar in states whose successor tariffs have not actually gone into effect yet to support the premise that these reforms did not negatively impact rooftop solar adoption rates. For instance, the Joint IOUs cite the continued growth of rooftop solar adoption in Duke Energy's service territory following successor tariff legislation in South Carolina in 2019, but do not mention that the changes to Duke Energy's NEM program will not go into effect until January 2022.[57] While Witness Tierney noted that the legislation itself "created some signals to the market with regard to the ability to reconsider the structure and level of that successor tariff," such signals would in fact be more likely to spur increases in adoption prior to the new tariff going into effect, rather than the negative impact on the market that one would expect when the customer economics actually change, so the lack of demonstrably negative impact on adoption thus far is not informative.[58] The Joint IOUs' reliance on rooftop solar growth in National Grid's service territory in New York is similarly flawed—the New York mass market decision of July 2020 also does not go into effect until January 2022.[59] And while the Sacramento Municipal Utility District ("SMUD") has adopted some features of NEM reform, such as "charges that are indicative of time-of-use rates, as well as a fixed charge," SMUD has not actually adopted a formal NEM successor tariff.[60]

For the areas whose reforms have gone into effect, the Joint IOUs gloss over the impacts to the rooftop solar market. For example, with regard to Nevada, solar adoption hit a near-complete plateau after a net billing tariff was adopted in 2016, which "decimated the rooftop solar market in Nevada for new systems, resulting in more than 1,000 immediate layoffs at solar companies, causing some of these companies to exit the market."[61] After "significant public outcry, a statewide ballot initiative, and lawsuits involving outraged solar customers, solar

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[57] *See id.* at 130:23–131:25 (S. Tierney, Joint IOUs).
[58] *Id.* at 131:18–22 (S. Tierney, Joint IOUs).
[59] *Id.* at 132:24–133:11 (S. Tierney, Joint IOUs).
[60] *Id.* at 134:6–13 (S. Tierney, Joint IOUs).
[61] Exh. SVS-01, Direct Testimony of S. Gallagher at 11:18–20.

companies, and the state," Nevada regulators and legislators changed course and restored net metering with a gradual stepdown system.[62] The Joint IOUs acknowledge that when Nevada restored net metering in 2017, adoption immediately recovered and the "market grew significantly more."[63] SEIA/Vote Solar attribute this recovery to "regulatory certainty through an orderly step down of the export rate," as well as "re-instilled consumer confidence in rooftop solar."[64]

Regarding Hawaii, the Joint IOUs characterize the post-reform adoption rate as "positive growth in cumulative capacity." However, between 2015 and 2018, following the first NEM reform, "total [photovoltaic] permits across the state dropped by over 60%," and "total solar jobs in Hawaii reached an all-time low of under 2000 across the state" between January and June 2017.[65] According to SEIA/Vote Solar Witness Will Giese, who is uniquely qualified in this proceeding to discuss Hawaii's situation based on his years as a director for the Hawaii Solar Energy Association, the growth that returned to the Hawaii rooftop solar market in 2019–2020 is "likely false positive growth as a result of companies looking to capitalize on a higher tax credit," not an indication of an otherwise healthy market, and "the Hawaiian solar market has yet to recover significantly" as of 2021.[66]

Finally, regarding Arizona, the Joint IOUs fail to account for the differences between the customer economics in Arizona versus California, as well as the differences between the way that export compensation is calculated. While Arizona has experienced growth in rooftop solar adoption since its 2016 reforms, "installed residential and commercial solar [photovoltaic] system prices for in [sic] Arizona as of the end of 2020 are 18% ($0.58/watt) and 28% ($0.61/watt) lower, respectively, than prices in California," meaning that the customer economics of adopting solar are far more flexible on export compensation since the cost to adopt is significantly lower.[67] Additionally, Arizona included consumer protections in its export compensation—while exports are valued at an approximation of avoided costs, there is a

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[62] *Id.* at 12:2–14.
[63] Tr. Vol. 1 at 133:28–134:4 (S. Tierney, Joint IOUs); *see also* Exh. IOU-01, Joint IOUs Direct Testimony at 35, Figure II-10.
[64] Exh. SVS-01, Direct Testimony of S. Gallagher at 12:16–18.
[65] Exh. IOU-01, Joint IOUs Direct Testimony at 35; Exh. SVS-02, Direct Testimony of W. Giese, at 8:15–16, 9:2–3.
[66] Exh. SVS-02, Direct Testimony of W. Giese at 12:10–17.
[67] Exh. SVS-01, Direct Testimony of S. Gallagher at 20:8–10.

limitation on export rate reductions of "no more than 10% annually."[68] Arizona's system also locks in export compensation at the time of interconnection for a ten-year period, which "afford[s] developers the ability to reasonably calculate a value proposition and estimated payback periods for new solar customers," and its grid access charge is $0.93/kW-dc, which is much lower than the GBC that the Joint IOUs have currently proposed.[69] Accordingly, it is not reasonable to expect a proposal like the Joint IOUs' to replicate the results seen in Arizona because the elements of the tariffs are so dissimilar.

(2) A glide path provides a proven method of avoiding market shock and maintaining regulatory certainty while shifting NEM policy to align with California's unique context and long-term goals for distributed generation and storage.

A glide path from the current retail rate-based compensation structure to an avoided cost-based export compensation structure has been shown to ease the market shock seen in jurisdictions like Nevada and Hawaii. Nevada is one example of a solar market that was severely disrupted by net metering reform, but recovered under a stepdown-based structure.[70] The following figure from Aurora Solar Witness Andrew Gong shows monthly residential solar installations in NV Energy's territory, with the export compensation structure for each period of time along the horizontal axis:[71]

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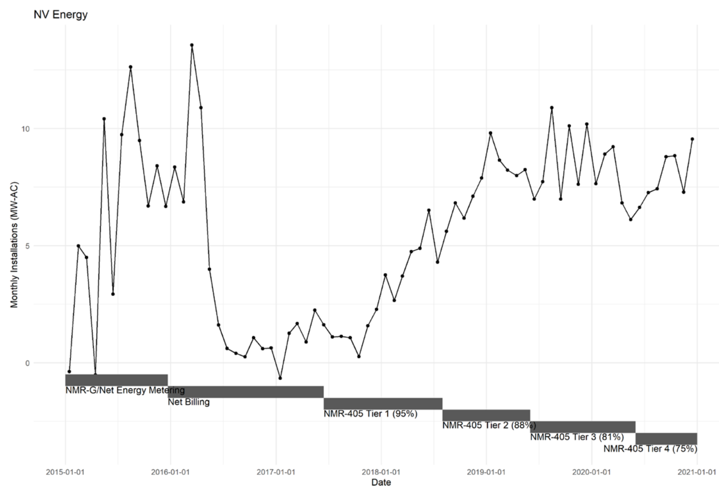
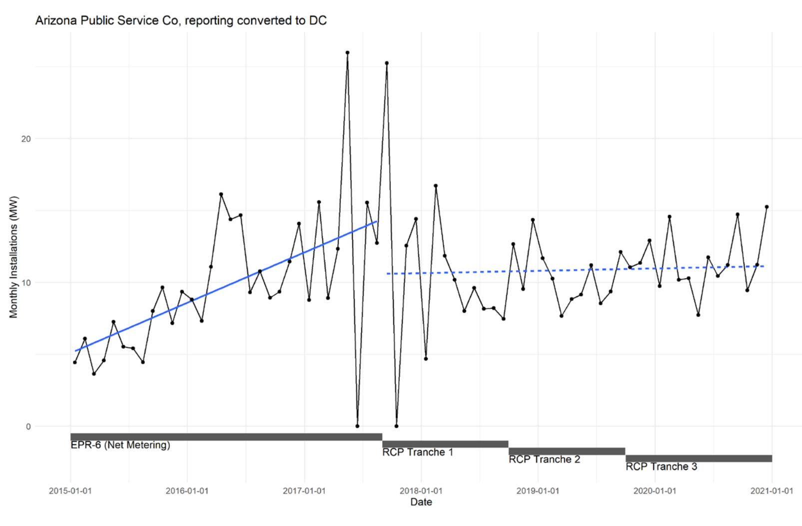
[68] *Id.* at 20:13–14.
[69] *Id.* at 20:16–21:2; *see also* Exh. IOU-01, Joint IOUs Direct Testimony at 142, Table IV-27 (describing the method of calculating the proposed GBC).
[70] *See* Exh. SVS-01, Direct Testimony of S. Gallagher at 12:15–13:4.
[71] Exh. ASO-02, Rebuttal Testimony of A. Gong at 12, *Figure 4: NV Energy Monthly Residential Installations*.



After the introduction of Tariff NMR-405 Tier 1, installations began to climb again, and despite the decline of export compensation for each subsequent tier, installations have continued to steadily increase, indicating that "a tariff with stepdowns can keep a stable rate of growth for solar."[72] The stark difference between the market impact of an immediate end to NEM versus the impact of a stepdown structure shows that a glide path is critical for providing industry stability.

Similarly, in Arizona, where reductions to export compensation are limited to no more than ten percent annually, average monthly installations stay relatively stable tranche by tranche.[73]



[72] *Id.* at 11:10–11.
[73] *Id.* at 10, *Figure 2: Corrected APS Monthly Residential Installations*.

Indeed, the E3 White Paper's proposal for a "market transition credit" ("MTC") is premised on the fact that "preservation of a viable market is likely to require a 'glide path.'"[74] Rather than thinking of the MTC as a separate mechanism, Sierra Club and other parties, such as the California Solar and Storage Association ("CALSSA"), SEIA/Vote Solar, and Aurora Solar, propose simple and understandable stepdown mechanisms with defined tranches, like those seen in Nevada post-2017, which the Commission should apply to successor tariff adoption.[75]

b) The Commission should set the initial export credit at electrification rates though a net billing mechanism which, unlike net metering, would not escalate over time.

The first step of a glide path to avoided cost compensation should reflect a meaningful reduction in export compensation compared to NEM 2.0 but not so drastic as to imperil the rooftop solar market in California. By decreasing the value of mid-day summer exports and substantially increasing the cost of energy during evening periods of little to no solar generation, Sierra Club's proposed electrification rates for successor tariff customers accomplish this objective. Through her bill impact analysis, Sierra Club Witness Dr. Camp determined that rooftop solar customers that moved from PG&E and SCE's default TOU rates to E-ELEC and TOU-D-PRIME respectively would have an approximately twenty percent reduction in bill savings.[76] This finding is consistent with the Joint IOU's analysis indicating cost-based rates reduce NEM compensation by twenty-two percent.[77]

To provide long-term certainty for successor tariff customers, Sierra Club recommends export compensation be locked in for twenty years, but unlike NEM, no longer escalate with retail rates.[78] Accordingly, as rates increase, the relative value of export compensation will

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[74] Successor Tariff White Paper at 3.
[75] *See* Exh. SVS-01, Direct Testimony of S. Gallagher at 21:10–22:2; Exh. CSA-01, Direct Testimony of B. Heavner and J. Plaisted at 6:26–7:6; Exh. ASO-01, Direct Testimony of A. Gong at 21:18–20.
[76] Exh. SCL-02, Direct Testimony of E. Camp at 19:18, 23:1.
[77] Exh. IOU-01, Direct Joint IOU Testimony at 101, Figure IV-29. An alternative approach is to differentiate initial export compensation among utilities to reflect higher SDG&E rates and lower SCE rates. Given SCE's lower rates and the sharp POP differential in TOU-D-PRIME, setting initial export compensation below electrification rates in SCE service territory would be the type of drastic cut that would chill sustainable growth of customer-sited renewable generation and should be avoided. Depending on the outcome of the electrification rate SDG&E ultimately adopts and its corresponding fixed charge component, initial export compensation could be set at a step-down from the initial electrification rate.
[78] Because Sierra Club's proposed export credit would not increase over time, Sierra Club believes it is

diminish, limiting future non-participant costs and increasing the incentive over time for on-site consumption through electrification, storage adoption, and load shifting.

Taken together, setting initial successor tariff export rates at electrification rates that do not escalate and untethering export compensation from retail rates is a meaningful reduction of non-participant impacts from NEM 2.0.[79] Importantly, while fixed export rates and underlying rates with high POP differentials are an adjustment from the current NEM 2.0 default TOU export compensation, it is a variation from the existing compensation structure that customers can easily understand and to which distributed generation providers are accustomed. In contrast, untested alternatives such as up-front payments and unpredictable export compensation are a significant change from NEM 2.0 and raise implementation and consumer protection concerns that risk stifling solar deployment.

c) The Commission should adopt capacity-based step-downs to avoided cost with a date certain set three months in advance of the next projected step-down.

The Commission should adopt step-downs to avoided cost compensation that are based on deployed capacity. Setting adjustments to incentives or export compensation according to calendar-based parameters (e.g., annual step-downs) fails to capture the relevant market conditions and can cause unintended stalls and rushes in adoption based on the artificial market condition they impose.

The experience of the California Solar Initiative ("CSI") program in developing a mechanism for gradual incentive declines is instructive.[80] Initially, the Commission approved

reasonable to lock in the export rate for a twenty-year period to provide long-term certainty to successor tariff customers. A shorter time frame, such as fifteen years, but in no case less than ten years, could also be appropriate.

[79] Sierra Club's support for transitioning away from retail rate compensation for exported customer generation in California should not be interpreted to suggest this is currently appropriate in other jurisdictions. In states with lower electricity rates and solar penetration, retail rate compensation can continue to serve as a reasonable proxy for the grid and societal benefits provided by customer-sited solar systems.

[80] *See* D.06-01-024, *Interim Order Adopting Policies and Funding for the California Solar Initiative* (Jan. 12, 2006) (authorizing the CSI Program and setting a combination time- and deployment-based system for triggering incentive reductions) ("D.06-01-024"); D.06-08-028, *Opinion Adopting Performance-Based Incentives, an Administrative Structure, and Other Phase One Program Elements for the California Solar Initiative* (Aug. 24, 2006) (revising the triggering mechanism to adopt a solely deployment-based system) ("D.06-08-028"); D.06-12-033, *Opinion Modifying Decision 06-01-024 and Decision 06-08-028 in Response to Senate Bill 1* (Dec. 14, 2006) (confirming the pure deployment-based mechanism while adjusting the deployment levels of each tranche to comply with SB 1) ("D.06-12-033").

the program with a combination system for reducing incentives. Incentives would be reduced annually, either on an automatic basis at the end of the calendar year or when deployment hit certain megawatt ("MW") benchmarks. Whichever condition was met first (*e.g.*, MW benchmark or December 31) would trigger the step-down.[81] However, upon reaching the first MW trigger, parties on all sides raised concerns about the implementation of the program, and the Commission revised its step-down structure in D.06-08-028 to adopt a purely MW deployment-based trigger system, with each IOU administering incentives based on the rate of adoption in its service territory.[82] While the utilities supported the initial combined system to preserve the program's budget, the Commission agreed with the solar parties' concerns about the artificial effects of time-based incentive reductions on the market, causing stalls when program funds for each year were exhausted and rushes to sign up for the program before an anticipated drop in incentive levels. The Commission also acknowledged the solar parties' and The Utility Reform Network's ("TURN") observation that a deployment-based mechanism responds directly to market conditions without requiring the Commission to constantly monitor the market.[83] While the levels of MW capacity in each tranche were adjusted thereafter to comply with SB 1 goals, the Commission did not alter its decision to remain on a purely deployment-based structure for incentives, and affirmed that such a structure was "simple, transparent and predictable and correspond[ed] to the economics of the solar marketplace without resource intensive reviews."[84]

To allow for more regulatory certainty in implementing a capacity-based step-down, each utility should set a date certain for the next step-down three months in advance of when the capacity limit is estimated to be reached based on a projection of deployment trends. This will allow for better planning and remove uncertainty as to which tranche a project may qualify for.

d) A 10 gigawatt glide path to export compensation at avoided cost is reasonable.

Sierra Club proposes a glide path to export compensation at avoided cost that is tied to achieving 10 gigawatts ("GW") of total deployment under the successor tariff for several

[81] D.06-01-024 at 24–25; *see also id.* at App. A, 15–16 (Table 5 shows the MW triggers and incentive levels).
[82] D.06-08-028 at 84–87.
[83] *Id.* at 85–87.
[84] D.06-12-033 at 10.

reasons. First, 10 GW is the approximate level of additional customer-sited solar deployment assumed under 2030 Integrated Resource Plan ("IRP") Scenario modeling.[85] Sierra Club recognizes that IRP modeling projections for deployment of customer solar are based off existing deployment trends, and there are alternative solutions to achieving the IRP GHG targets. Nonetheless, Sierra Club believes a 10 GW glide path is a useful guidepost that strikes the appropriate balance between utility-scale and distributed resource development. This balance furthers a variety of objectives, including the protection of undeveloped lands and provision of generation in local capacity areas that will help enable the retirement of gas plants in disadvantaged communities.

Notably, a 10 GW glide path constitutes only a small fraction of the additional customer-sited solar resources California will likely need to meet SB 100 requirements. The SB 100 Joint Agency Report assumes deployment of over 28 GW of additional customer-sited solar by 2045.[86] Achievement of the 10 GW glide path therefore represents less than half of SB 100 projections for customer-sited generation. As illustrated below, even with this level of distributed solar deployment, the SB 100 Joint Agency Report assumes almost 70 GW of additional utility-scale solar, far more than what is currently deployed in California.[87]

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[85] D.20-02-028, *2019-2020 Electric Resource Portfolios to Inform Integrated Resource Plans and Transmission Planning*, at 42–43 (Mar. 26, 2020) (identifying 9,827 MW of deployment in 2020 and 20,066 MW by 2030), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M331/K772/331772681.PDF.
[86] Exh. SCL-01, Direct Testimony of M. Vespa at 28:30–29:1 (citing CEC, CPUC, CARB, *2021 SB 100 Joint Agency Report Summary, Achieving 100% Clean Energy Electricity in California*, at 10, Docket No. 19-SB-100 (Mar. 15, 2021)).
[87] *Id.* at 29:1–6.

Modeling Results

Clean Electricity Resources

To reach the 2045 target, California will need to roughly triple its current electricity power capacity. The projected increase is driven by the conversion to clean energy resources and growing electricity demand.

California Clean Electricity Resources	Existing Resources 2019*	Projected New Resources 2030**	Projected New Resources 2045**
Solar (Utility-Scale)	12.5 GW	16.9 GW	69.4 GW
Solar (Customer)	8.0 GW	12.5 GW	28.2 GW
Storage (Battery)	0.2 GW	9.5 GW	48.8 GW
Storage (Long Duration)	3.7 GW	0.9 GW	4.0 GW
Wind (Onshore)	6.0 GW	8.2 GW	12.6 GW
Wind (Offshore)	0 GW	0 GW	10.0 GW
Geothermal	2.7 GW	0 GW	0.1 GW
Biomass	1.3 GW	0 GW	0 GW
Hydrogen Fuel Cells	0 GW	0 GW	0 GW
Hydro (Large)	12.3 GW	N/A†	N/A†
Hydro (Small)	1.8 GW	N/A†	N/A†
Nuclear	2.4 GW	N/A†	N/A†

*Includes in-state | **Includes in-state and out of state capacity | †New hydro and nuclear resources were not candidate technologies for this round of modeling and could not be selected*

A 10 GW glide path appropriately recognizes the importance of continued rooftop solar deployment in limiting the land use impacts of utility-scale solar. Failure to achieve rooftop solar deployment levels in IRP modeling and in the SB 100 Joint Agency Report means more development pressure on California's open spaces, working lands, and sensitive habitats.[88] This is already occurring at current deployment levels. As one recent example, despite the California Fish and Game Commission recently moving forward with a petition to determine whether the Western Joshua Tree should be designated a threatened or endangered species and granting it temporary endangered species status, 15 proposed utility-scale solar projects sited in Joshua Tree habitat were nonetheless allowed to proceed under an emergency authorization, permitting the

[88] *Id.* at 29:7–11. Central-station solar photovoltaic plants with fixed arrays or single-axis tracking typically require 7.5 to 9.0 acres per MW-AC, or 3.3 to 4.4 acres per GWh per year. *Id.* at 29, n.74 (citing Sean Ong et al., *Land-Use Requirements for Solar Power Plants in the United States*, National Renewable Energy Laboratory, at Table ES-1 (June 2013)). 69.4 GW of solar would occupy roughly 500,000 to 600,000 acres.

razing of this species.[89] California has recognized the importance of preserving its natural and working lands, with a recent Executive Order committing "to conserve at least 30 percent of California's land and coastal waters by 2030."[90] In planning for the appropriate ratio of utility-scale to distributed solar in California's clean energy future, the Commission should consider the preservation of California's natural heritage and open space. A 10 GW capacity target, which would still require substantial additional rooftop solar deployment at avoided cost compensation to meet SB 100 objectives, strikes this balance.

Party assertions that California can meet its climate objectives absent substantial additional deployment of rooftop solar do not withstand scrutiny. While parties like the California Wind Energy Association ("CalWEA") stress that "this customer-side capacity addition was a fixed input into the SB 100 RESOLVE model, not the output or a result of an optimum RESOLVE model run," the fact that additional customer-sited solar was assumed in the model rather than evaluated against alternatives does not mean it is unnecessary to achieve the goals of SB 100.[91] CalWEA's attempt to provide an alternative scenario is unpersuasive as it depends on continued operation of aging gas plants and ignores the importance of generating resources in local capacity areas.

CalWEA suggests that reducing the projected amount of distributed solar generation on the grid would provide a positive effect by reducing the need for storage, which would in turn allow gas resources to stay online for resource adequacy purposes, and would make wind and geothermal generation more cost-effective.[92] CalWEA's assessment ignores the cost, market power, and reliability concerns of attempting to keep an aging gas fleet operational, as well as equity concerns of retaining gas-fired generation, which is disproportionately located near communities with high cumulative socioeconomic and environmental burdens. SB 100 alternative proposals that depend on retaining additional gas generation to meet resource adequacy needs are antithetical to the state's climate and equity objectives.[93]

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[89] *Id.* at 29:12–30:4 (citing Louis Sahagún, *California grants western Joshua trees temporary endangered species protections*, LA Times (Sept. 22, 2020)).
[90] Exec. Order N-82-20 (Cal. Oct. 2020), https://www.gov.ca.gov/wp-content/uploads/2020/10/10.07.2020-EO-N-82-20-signed.pdf.
[91] Exh. CWA-01, Rebuttal Testimony of D. Shirmohammadi at 5:22–24.
[92] *Id.* at 9:4–12.
[93] Indeed, the urgency of retiring fossil fueled resources to address the climate emergency has only

By proposing to increase reliance on utility scale renewables at the expense of distributed resource deployment, CalWEA's assessment also ignores the critical importance of customer-sited generation to decrease reliance on gas plants and their supporting infrastructure in local capacity areas. Local capacity requirements for 2021 are over 21 GW, of which approximately 14 GW are being met with gas-fired generation.[94] Local capacity areas and sub-areas have limited transmission capability and therefore rely on in-basin resources to be available to serve local need in the event of a transmission contingency. For batteries to displace other local capacity resources in the event of a transmission outage, remaining "resources must be sufficient to recharge the batteries in anticipation of the outage continuing through the night and into the next day's peak load period."[95] Local capacity areas with significant amounts of gas generation in disadvantaged communities, such as the Western LA Basin, are largely developed and therefore cannot accommodate utility-scale renewables to serve as a local generation source to charge batteries in the event of an extended transmission contingency. At a July 9, 2021 Integrated Energy Policy Report ("IEPR") Joint Agency Workshop on Summer 2021 Electric and Natural Gas Reliability, the importance of customer-sited solar generation was also discussed by the California Independent System Operator ("CAISO") as it pertained to the potential to enable retirement of gas-fired generation in the LA Basin and facilitate the closure of the Aliso Canyon storage facility.[96] At the IEPR workshop, Neil Millar, CAISO Vice President of Infrastructure and Operations Planning, used an example from the 2022 Local Capacity Study showing the potential for local area need in the LA Basin to be met with incremental energy storage. While the potential for energy storage to meet local capacity need under the LA

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accelerated. Governor Newsom recently issued a Proclamation of a State of Emergency regarding resource adequacy and climate change, stating that "actions to accelerate procurement and deployment of clean energy projects will help prevent future emergency shortfall situations, and advance the State's progress toward achieving its clean energy goals, including the retirement of fossil fuel resources." Cal. Exec. Department, *Proclamation of a State of Emergency* (Jul. 30, 2021), https://www.gov.ca.gov/wp-content/uploads/2021/07/Energy-Emergency-Proc-7-30-21.pdf.

[94] Exh. SCL-01, Direct Testimony of M. Vespa at 30:14–16 (citing CPUC, *The State of the Resource Adequacy Market – Revised* at 17 (Jan. 13, 2020), https://www.cpuc.ca.gov/RA/).

[95] *Id.* at 30:20–22. (citing R.19-11-009, *CAISO Final Local Capacity Technical Study for 2021* at 3 (May 1, 2020), https://www.caiso.com/Documents/May1-2020-Final-2021-LocalCapacityTechnicalStudyReport-R19-11-009.pdf).

[96] Exh. SCL-03, Rebuttal Testimony of M. Vespa at 6:13–18 (citing IEPR, Joint Agency Workshop on Summer 2021 Electric and Natural Gas Reliability – Day 2, Session 4 (July 9, 2021), https://www.energy.ca.gov/event/workshop/2021-07/iepr-joint-agency-workshop-summer-2021-electric-and-natural-gas-1).

Basin's current load duration curves is limited, as Mr. Millar observed, "The good news though is that with behind-the-meter solar being so common, that actually sharpens our peak demand window and the post-solar window and it increases the opportunity for storage to be a major player… in helping with local capacity."[97] CalWEA's alternative, which relies on utility scale wind, geothermal and continued operation of gas generation in lieu of customer-sited solar generation and batteries, would deprive California of a critical tool to enable the retirement of gas-fired generation in disadvantaged communities in local capacity areas, and would support continued reliance on gas infrastructure such as the Aliso Canyon storage facility, which remains in service in part to support gas plant operations. Distributed generation is a key part of local reliability solutions that enable the retirement of gas generation in local capacity areas and achieve California's decarbonization objectives. Accordingly, Commission policies should be designed to ensure continued deployment at the levels set forth in the SB 100 Report.

e) Application of the step-downs to avoided cost export compensation.

To reach avoided cost after 10 GW of deployment, Sierra Club proposed ten 1 GW step-downs. Each tranche would be 1 GW, divided proportionally between IOUs based on the ratio of the electrical corporation's peak demand compared to total statewide peak demand.[98] All customer-sited generation taking service under the successor tariff, including solar on new construction under Title 24, programs targeted at low-income customers, and non-residential solar in the utility's service territory would count toward meeting the step-downs for export compensation for general market residential successor tariff customers. The reason for including all successor tariff enrollment in calculating step-downs rather than just residential is because the 10 GW glidepath is based off of SB 100 and IRP scenarios for total rooftop solar deployment.

Export compensation would first be set equal to the IOUs' respective qualifying successor tariff rate at 2021 values, and dropped down by 10 percent per tranche of the difference between the eligible 2021 retail rate value and avoided cost for that TOU period, as determined by the ACC in effect at the time the step-down is calculated. Sierra Club proposes using short-run ACC values rather than a long-run leveled value. To the extent ACC values

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[97] *Id.* at 7:2–6 (citing IEPR, Joint Agency Workshop on Summer 2021 Electric and Natural Gas Reliability, Session 4, at 58:43 (July 9, 2021)).

[98] *See, e.g.*, Pub. Util. Code § 2827.10(c)(1) (using this method to allocate 500 MW limit for enrollment in fuel cell net metering program).

increase in subsequent ACC iterations such that an existing solar customer would receive lower export compensation than a prospective customer, export compensation would increase to match compensation awarded to prospective customers.

As an example, under SCE's TOU-D-PRIME rate, off-peak summer rates are currently \$0.17/kWh. The initial tranche of successor tariff customers would receive an export credit during those hours of \$0.17/kWh to match the eligible rate, and would receive this compensation for the next 20 years. Once this initial tranche is filled, new residential successor tariff customers would be compensated at the avoided cost plus 90% of the difference between the eligible 2021 retail rate and the avoided cost averaged over that TOU period. That is, if avoided cost averaged over this TOU period for off-peak hours were hypothetically \$0.07/kWh, because the 2021 TOU-D-PRIME rate for that period is \$0.17 kWh, the second tranche of successor tariff customers would receive avoided cost (\$0.07/kWh) plus 90% of the difference between avoided cost and the 2021 retail rate (approximately \$0.09/kWh), which equals \$0.16. Assuming avoided costs were the same at the time of the next step-down, export compensation would be lowered to \$0.15/kWh (avoided cost (\$0.07/kWh) plus 80% of the difference between avoided cost and the retail rate (approximately \$0.08/kWh).

As another example, for summer peak export compensation (weekdays from 4 p.m. to 9 p.m.), if avoided cost over this period hypothetically averaged at \$0.24, because the 2021 TOU-D-PRIME rate is \$0.44, the second tranche of successor tariff customers would receive avoided cost (\$0.24) plus 90% of the difference between avoided cost and the 2021 retail rate (approximately \$0.17), for an export rate of \$0.41 during summer peak periods. Step-downs would decrease export compensation by an additional 10% of the difference between retail and avoided cost per tranche until the export rate is equal to avoided cost.

3. Element 3: Non-Bypassable Charges on Gross Consumption

Sierra Club did not initially propose changes to assessing NBCs on successor tariff customers from NEM 2.0, which charges NBCs based on imported energy. Having reviewed party testimony on this issue and given the broader societal purpose of NBCs (which includes funding public purpose programs, nuclear decommissioning and wildfire liability costs), Sierra Club supports successor tariff customers fully contributing to established NBCs based on their total energy consumption.[99] In determining NBCs for a successor tariff customer's gross energy consumption, the Commission should ensure successor tariff customers have the option of utilizing methodologies that avoid the added cost of separate metering and minimize administrative complexity, such as through a per kW charge based on average system performance. Specific methodologies for determining NBCs for successor tariff customers could be finalized though an advice letter process and use data on modeled system performance to estimate annual generation and the average percentage of that generation that is consumed behind the meter.

4. Element 4: Systems Sized For an All Electric Home with Any Net Surplus to Fund Low-Income Clean Energy Programs

Current NEM 2.0 tariffs implement the statutory eligibility requirement that NEM customers' generation facilities be "intended primarily to offset part or all of the customer's own electrical requirements"[100] by assessing historical load data for the customer to determine the customer's "electrical requirements" and limiting system sizing based on that data.[101] For any electricity that is produced in excess of a NEM customer's on-site load at the end of a 12-month true-up period, the NEM customer receives NSC. Pursuant to D.11-06-016, NSC is calculated as a simple rolling average of the IOUs' default load aggregation point price from 7 a.m. to 5 p.m., corresponding to the customer's 12-month true-up period.[102] The rate is typically "approximately $0.02 to $0.03 per kWh."[103]

With the state's focus on widespread electrification as a key policy to reach California's

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[99] *See, e.g.,* Exh. PAO-01, Cal Advocates Direct Testimony at 3-38–3-41. NBCs to which successor tariff customers would fully contribute are the same as those identified in the NEM 2.0 Decision. D.16-01-044, *Decision Adopting Successor to NEM Tariff*, at 89 (Feb. 5, 2016) (with Department of Water Resources bond charges having transitioned to wildfire funds) ("D.16-01-044"), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K181/158181678.pdf.

[100] Pub. Util. Code § 2827(4)(A); § 2827.1(a) (defining "eligible customer-generator" for the purposes of the NEM 2.0 Tariff as the same definition from § 2827(4)(A)).

[101] *See*, *e.g.*, SCE, *Schedule NEM-ST Net Energy Metering Successor Tariff*, Special Condition 1(b)(iii), at Sheet 9 (effective Apr. 15, 2021), https://library.sce.com/content/dam/sce-doclib/public/regulatory/tariff/electric/schedules/other-rates/ELECTRIC_SCHEDULES_NEM-ST.pdf.

[102] D.11-06-016, *Decision Adopting Net Surplus Compensation Rate Pursuant to Assembly Bill 920 and the Public Utility Regulatory Policies Act of 1978*, at 65, Ordering ¶ 1 (June 9, 2011).

[103] CPUC, *Net Energy Metering*, https://www.cpuc.ca.gov/NEM/ (last visited Aug. 30, 2021). *See also* PG&E, *Net Surplus Compensation Rates for Energy* (2021) (Net Surplus Compensation Rates from PG&E for January 2019–June 2021 varying between approximately $0.02/kWh to $0.03/kWh), https://www.pge.com/pge_global/common/pdfs/solar-and-vehicles/green-energy-incentives/AB920_RateTable.pdf.

decarbonization objectives, continued reliance on historical load data where a customer has not yet adopted electrification technologies could function to discourage their future adoption by reducing the operational savings achieved through electrification. For the successor tariff to be "coordinated"[104] with the Commission and the State's climate and decarbonization policy, sizing requirements should be based on annual load that incorporates a reasonable approximation of demand with electric appliance and vehicle adoption.

Notably, a recent interim decision in Connecticut updated its system size policy to further its electrification goals, stating:

> [I]n order to promote the state's policy goals with respect to vehicle electrification and fuel switching as noted by stakeholders in the above-captioned proceeding, the [IOUs] shall allow the system to be sized based on the historical load parameters above *plus* a reasonable approximation of the annual load of two electric vehicles and, for non-electric heating customers, a reasonable approximation of the incremental electric load associated with fuel switching. These approximations may be applied to each Residential Tariff application and do not have to be unique or specific to each application or customer.[105]

To facilitate building and vehicle electrification, the Commission should adopt a similar policy for determining system size requirements.

To the extent allowing systems larger than historic usage to facilitate future electrification is a concern, rather than provide a bill credit or payment for NSC to the successor tariff customer, the Commission should require that NSC be directed to clean energy programs targeting low-income ratepayers. This approach for NSC is used in Oregon[106] and would avoid a potential circumstance where systems are oversized to take advantage of NSC without future adoption of electrification technologies. It would also advance equity objectives by providing additional resources to low-income programs until the customer's electric load is increased

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[104] *See* D.21-02-007 at 46, Principle (e).
[105] Exh. SCL-01, Direct Testimony of M. Vespa at 33–34, n.85 (citing State of Connecticut, Public Utilities Regulatory Authority, Docket No. 20-07-01, *Interim Decision*, at 16 (Feb. 10, 2021), http://www.dpuc.state.ct.us/DOCKCURR.NSF/8e6fc37a54110e3e852576190052b64d/a21495b0e4968ba68525869900545978/$FILE/200701-021021.pdf).
[106] *See* Portland General Elec. Co., *Schedule 215: Solar Payment Option Pilot, Small Systems (10 kW or Less)*, at 2 (effective Sept. 21, 2015), https://assets.ctfassets.net/416ywc1laqmd/7pnrjJtnZJhkh7DzUZe5xD/6c4d11952cb74e82f19f2f2539959f66/Sched_215.pdf. ("[A]t GCB of each generation year, any excess generation kWh credits accumulated will be transferred to the Company's low income assistance program at the average annual Schedule 201 Avoided Cost rate.").

through electrification of fossil-fueled end uses.

5. Program elements that should *not* be included in the successor tariff

a) Grid Benefits Charge

Sierra Club opposes the inclusion of a GBC, like the one proposed by the Joint IOUs, which would be a "$/kW-month Grid Benefits Charge based on a customer's installed system size, net of any avoided cost benefits."[107] Fixed charges are appropriately assessed only for customer costs that are not dependent upon usage. Further, the GBC, when combined with export compensation at avoided costs, creates a successor tariff structure that fails to meet the minimum requirements of the Public Utility Regulatory Policies Act ("PURPA").[108]

(1) An additional fixed charge is not an appropriate method of cost recovery for consumption-dependent costs.

As SEIA/Vote Solar have explained, charges like the GBC can "drive customers away from solar and storage DERs, even though solar provides the less-expensive, on-site, off-peak clean power needed to supply other types of DERs, and storage addresses the state's critical needs for peak capacity and improved resilience."[109] Fixed charges are most appropriately assessed for "costs that do not depend on the customer's usage," such as "the cost of hooking up to the system," and limited to "about the 12 to 15-dollar range."[110]

The stated goal of the GBC is to recover a portion of costs that the customer-generator avoids through self-consumption, which are collected on a volumetric basis from other

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[107] Exh. IOU-01, Direct Joint IOU Testimony at 135:16–17. Cal Advocates also propose a GBC that contains a "dollar per kW of installed system capacity charge per month" to collect infrastructure costs for distribution and transmission in addition to assessing NBCs based on monthly gross consumption. *See* Exh. PAO-01, Cal Advocates Direct Testimony at 3-40:16–19.

[108] Requiring NBCs be assessed on gross consumption does not present the same PURPA concerns as a GBC. Recovering costs from residential successor tariff customers through NBCs that are assessed on gross consumption is consistent with the Joint IOUs' contention that when rooftop solar customers consume their generation on-site, while they may be reducing their imports, they are not reducing their consumption, unlike a customer who has reduced their consumption by adopting energy efficiency measures or making behavioral shifts. Exh. IOU-01, Direct Joint IOU Testimony at 102:5–8. By instead assessing the NBCs on all consumption—including consumption of electricity generated on-site—these costs can still be recovered from residential successor tariff customers without disincentivizing the customer from adopting energy efficiency measures or creating a solar-only charge that runs afoul of PURPA.

[109] Exh. SVS-03, Direct Testimony of T. Beach at 37:18–22.

[110] Tr. Vol. 8 at 1419:5–12 (T. Beach, SEIA/Vote Solar).

customers.[111] However, the GBC is not assessed based on the actual volume of the customer's consumption, but rather, based on the size of their installed system and the "average export percentage of that customer class over the previous year" in each IOU's service territory.[112] As Joint IOU Witness Morien acknowledged, due to the nature of averages, it is possible that some customers would be overcharged if they consumed less of their generation onsite.[113] The GBC's imprecise and fixed nature is not an appropriate basis for a monthly charge aimed at recovering costs that are collected on a volumetric basis from other customers of the same class. Further, because the customer cannot control the average self-consumption rate of all successor tariff customers in their utility's service area, it is an uncontrollable and unavoidable fixed charge that would disincentivize residential successor tariff customers from adopting energy efficiency measures or practices.[114] Cal Advocates' GBC similarly contains a portion that is a fixed cost per installed kW to recover distribution and transmission costs that runs into the same issue—recovering these costs through a fixed charge when they are typically recovered through volumetric rates for other residential customers leads to the same imprecise outcomes as the Joint IOUs' GBC.[115]

(2) The GBC is not PURPA-Compliant.

The structures of the GBC proposed by the Joint IOUs and the distribution and transmission portion of the GBC proposed by Cal Advocates are not PURPA-compliant, and even if they were, their inclusion would cause the Joint IOUs' and Cal Advocates' proposals to be worse customer offers than the minimum requirements under PURPA, which gives rooftop solar generators certain rights as qualifying facilities ("QFs").[116] Under PURPA, QFs have the right to purchase services such as supplementary or backup power from their utility at a just, reasonable, and non-discriminatory rate.[117]

For import rates to be PURPA-compliant, the rate the QF pays the utility for energy

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[111] *See* Tr. Vol. 3 at 421:15–19 (G. Morien, Joint IOUs).
[112] Exh. IOU-01, Direct Joint IOU Testimony at 138:6–7.
[113] Tr. Vol. 3 at 420:10–421:1 (G. Morien, Joint IOUs).
[114] *See id.* at 422:11–20 (G. Morien, Joint IOUs).
[115] Exh. PAO-01, Cal Advocates Direct Testimony at 3-40:16–19.
[116] 18 C.F.R. §§ 292.203(a), 292.204 (setting forth eligibility criteria for "qualifying small power production facilities" that include "renewable resources" as a primary energy source and up to 80 MW as maximum size).
[117] *Id.* § 292.305; 16 U.S.C. § 824a-3(a), (c); *Fed. Energy Regul. Comm'n v. Mississippi*, 456 U.S. 742, 750–51 (1982).

imports must be "a rate applicable to a non-generating [customer of the same customer class] unless the electric utility shows that a different rate is justified on the basis of sufficient load or other cost-related data."[118] If a utility seeks to justify a different rate for sales to QFs on the basis of load or cost-related data, the rate must be "based on accurate data and consistent systemwide costing principles . . . to the extent that such rates apply to the utility's other customers with similar load or other cost-related characteristics."[119] The utility must ensure that a QF "will not be singled out to lose any interclass or intraclass subsidies to which it might have been entitled had it not generated part of its electric energy needs itself."[120] Both the Joint IOUs' and Cal Advocates' GBC proposals violate these standards. The GBCs would collect distribution and transmission costs through a fixed charge from solar customers, even though the utilities recover these exact same costs from other customers through volumetric charges under their (otherwise) systemwide costing principles.

Accordingly, a successor tariff customer would be subject to a charge that could be higher than what they would have paid through their volumetric rate had they not self-generated some of their electricity. For example, as SEIA/Vote Solar Witness Beach observed, under the GBC, "when the solar customer goes on vacation, they will have to pay the full GAC for that month, even though their usage of solar power behind the meter may drop substantially that month. If the system is down for a period to replace the inverter, the customer will still pay the GAC as though the system is operating."[121] Conversely, a residential customer without a rooftop solar system who goes on a month-long vacation would pay almost nothing toward the shared costs allocable to the GBC because those costs would be assessed based on their minimal volumetric usage.

Additionally, a customer-generator's export rate meets PURPA's minimum requirements "if the rate equals [] avoided costs," and may only be lower than avoided cost value if the state regulatory authority determines a lower rate is just, reasonable, in the public interest, and "sufficient to encourage" small power production.[122] Under the Joint IOUs' and Cal Advocates' proposals, successor tariff customers would receive export compensation at avoided costs, but

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[118] 18 C.F.R. § 292.305(a)(1)(ii); 45 Fed. Reg. 12,214, 12,228 (1980).
[119] 18 C.F.R. § 292.305(a)(2).
[120] 45 Fed. Reg. at 12,228.
[121] Exh. SVS-03, Direct Testimony of T. Beach at 71:21–24.
[122] 18 C.F.R. § 292.304(b)(3).

would also be subject to the fixed GBC.[123] The result is a lower overall value for the customer-generator than simply adopting avoided cost export compensation without also adopting a discriminatory rate for imports. The current NEM 1.0 and 2.0 tariffs provide export compensation to customer-generator QFs that far exceeds the PURPA minimum, but customers who choose not to enroll in the NEM tariff can still interconnect under Electric Rule 21 and simply receive the PURPA-mandated minimum avoided cost compensation for exports.[124] By providing a worse customer value proposition than the PURPA minimum, the proposals for GBCs reach illogical results and raise consumer protection concerns.

b) TOU netting

The Commission should not adopt the Joint IOUs' TOU netting proposal, which states that "exports may only be netted within their respective time-of-export period."[125] The Joint IOUs assert that limiting export credits to offset only imports during the same TOU period "will provide more accurate price signals for customers, further encourage load shifting, and ensure that customers exporting during the middle of the day are not able to use these credits to offset increased consumption during the evening peak period."[126] However, as Joint IOU Witness Morien acknowledged, rates with high, cost-based TOU differentials "are designed" to encourage load shifting, and a customer enrolled in a rate with cost-based TOU differentials would still have an incentive to load shift due to the price signals in the rate even without TOU netting.[127]

Additionally, as export compensation declines from retail rates, the incentive to load shift increases.[128] For example, under SCE's TOU-D-PRIME rate, as described in the Joint IOUs' proposal, the on-peak summer rate is approximately 45 cents, compared to the off-peak summer

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[123] *See* Exh. IOU-01, Direct Joint IOU Testimony at 18:1–8; Exh. PAO-01, Direct Cal Advocates Testimony at 1-6:8–15.
[124] *See* R.17-07-007, *Order Instituting Rulemaking to Consider Streamlining Interconnection of DERs and Improvements to Rule 21*, at 2–3 (Jul. 21, 2017) ("Rule 21 governs CPUC-jurisdictional interconnections, which include the interconnection of all net energy metering (NEM) facilities, "Non-Export" facilities, and qualifying facilities intending to sell power at avoided cost to the host utility . . . As initially adopted, Rule 21 was designed to meet the needs of small, non-utility-owned generating facilities, namely qualifying facilities . . . as defined by the Public Utility Regulatory Policies Act."), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M192/K079/192079467.PDF.
[125] Exh. IOU-01, Direct Joint IOU Testimony at 103:7–8.
[126] *Id.* at 103:8–11.
[127] Tr. Vol. 4 at 588:9–18 (G. Morien, Joint IOUs).
[128] *Id.* at 592:27–593:4.

rate of $0.17, which is a 2.6:1 differential.[129] Put differently, even if the customer were compensated for exports at the retail rate, they would need to generate 2.6 kWh during the off-peak midday TOU period to offset 1 kWh of evening grid consumption. Decoupling export compensation from the retail rate and assigning an even lower value to midday exports will increase the amount of midday kWh the customer would need to generate to offset evening imports. As Joint IOU Witness Morien stated, the TOU netting concept is "more important for situations in which there might be a higher export compensation rate."[130] Under Sierra Club's proposal, TOU netting is unnecessary to provide a price signal to load shift, both because successor tariff customers are required to enroll in highly differentiated electrification rates and because export compensation rates do not increase with retail rates, and will decrease with each proposed step-down.

c) Unpredictable export compensation

The Commission should reject successor tariff elements that lead to unpredictable export compensation. Without predictable parameters by which to calculate export compensation, solar industry participants cannot provide consumers with accurate estimates since "it is not possible to predict the lifetime bill savings of a [photovoltaic] system if the export rates are subject to uncertainty."[131] An uncertain structure for export compensation that would update on a three year cycle was attempted in New York, but "public pushback due to complexities in modeling resulted in a 10-year lock and an extension of standard NEM for customers below 750 kW."[132] As Aurora Solar Witness Gong noted, it is not the concept of an element that changes over time that is inherently detrimental, but rather the unpredictability of the changes; as long as "the consumer can be confident that the contract they signed is reflected in the product and savings they get later," a changing element, such as predetermined step-downs in export compensation, is appropriate.[133]

Party proposals like that of the Joint IOUs include multiple layers of uncertainty that present consumer protection and transparency concerns. First, export compensation that changes

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[129] Exh. IOU-01, Direct Joint IOU Testimony at 123, Table IV-20.
[130] *See* Tr. Vol. 4 at 591:5–10.
[131] Exh. ASO-01, Direct Testimony of A. Gong at 15:25–26.
[132] *Id.* at 16:6–11.
[133] *Id.* at 7:2–5.

annually as the avoided cost calculator is updated provides obvious uncertainty.[134] In addition, the Joint IOUs propose to take the values from the avoided cost calculator and weigh them by the customer's metered export profile, which the customer cannot know until their system is installed and operating.[135] On top of these factors, the customer's export profile would be updated annually and could change over time as the mix of technologies participating in the successor tariff evolves, meaning the value of their export compensation "would in part depend on what other customers in their service territory are installing."[136] Proposals with highly variable and unpredictable export compensation rates should not be adopted.

D. Scoping Memo Issue 5: Which of the analyzed proposals should the Commission adopt as a successor to the current net energy metering tariff and why? What should the timeline be for implementation?

1. The Commission should adopt the elements of Sierra Club's successor tariff proposal.

The Commission should adopt the four elements of Sierra Club's proposed successor tariff. Some of these elements should be adopted as proposed, others allow for variation. Taking service under an electrification rate with an approved or agreed upon fixed charge component, such as SCE's TOU-D-PRIME rate or PG&E's proposed E-ELEC rate, is a key element that the Commission should adopt as proposed. Because the fixed charges in electrification rates function to decrease volumetric rates, they are a superior alternative to GBCs in recovering fixed costs. In addition, as Sierra Club Witness Dr. Camp determined, electrification rates without fixed charges, such as EV2, provide less of an incentive for customers to electrify their homes and vehicles.[137] Requiring successor tariff customers to enroll in electrification-friendly rates: 1) incentivizes deeper decarbonization through electrification of fossil fueled end-uses to further California's climate and clean energy objectives pursuant to Principle (e); 2) maximizes value of customer-sited renewable generation to all customers and to the electric system pursuant to

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[134] *See* Tr. Vol. 5 at 816:27–817:5 (C. Kerrigan, Joint IOUs); Exh. IOU-01, Direct Joint IOU Testimony at 94:11–13; Exh. PAO-01, Direct Testimony of Cal Advocates at 3-8:7–10.
[135] Tr. Vol. 5 at 817:6–23 (C. Kerrigan, Joint IOUs). Cal Advocates similarly proposes to set export compensation at "average [photovoltaic] production-weighted avoided costs during the middle of the day and at simple average avoided costs during evenings hours." Exh. PAO-01, Direct Cal Advocates Testimony at 3-16:9–11.
[136] Tr. Vol. 5 at 820:22–821:2 (C. Kerrigan, Joint IOUs); Exh. IOU-01, Direct Joint IOU Testimony at 127:5–6.
[137] Exh, SCL-02, Direct Testimony of Dr. Camp at 3:22–23.

Principle (g); 3) improves equity among customers pursuant to Principle (b); and 4) creates uniformity across utilities pursuant to Principle (f).

The Commission should also adopt a glide path to avoided cost export compensation through capacity-based step-downs to ensure sustainable growth of customer-sited generation as required under Public Utilities Code Section 2827.1. With regard to this element, Sierra Club is not wedded to one particular approach. What matters is that step-downs are gradual and there is a long-term lock-in of export compensation to enable the successor tariff to be understandable and to enhance consumer protection by providing a reasonable level of certainty in a customer's investment decision pursuant to Guiding Principles (c) and (f). Sierra Club has proposed ten 1 GW step downs to avoided cost, starting at the IOUs' eligible 2021 electrification rate with export compensation locked in for each step for a 20-year period. A glide path that differentiated the initial step down to reflect the variations in utility rates (for example, with SDG&E starting at below their electrification rate) or a different time horizon for the long-term lock-in of export compensation would also be reasonable depending on the extent to which the Commission adopted elements not included in Sierra Club's proposal that would reduce customer savings from deployment of behind-the-meter generation.

With regard to allowing systems to be sized to meet the future energy demands of a fully electrified household, Sierra Club proposes to require the value of any NSC be directed to fund low-income clean energy programs rather than be credited to the customer. This proposal best incentivizes future electrification and removes any potential to oversize systems to take advantage of surplus credit. The Commission should ensure the successor tariff does not inhibit future electrification by imposing unnecessary limits on system size based on historic energy consumption.

Under E3's analysis, Sierra Club's proposal has TRC scores above one for all utilities for non-CARE solar+storage customers by 2030.[138] This does not account for the inclusion of NBCs on gross consumption which Sierra Club has now incorporated into its proposal. E3's analysis for solar only customers in 2030 has a TRC score above one only for SCE. However, the analysis assumes solar systems are sized to meet 100 percent of customer's annual load,[139] an

[138] Exh. CSA-32, Pages From Updated Cost-Effectiveness of NEM Successor Rate Proposals 06-15-2021 at 58.
[139] *Id.* at 31.

outcome Sierra Club believes is unrealistic given that by 2030, export compensation would be at short-run avoided cost and mid-day exports would offset a small fraction of the cost of imported energy. E3's 2023 results show that Sierra Club's proposal does not have a TRC score above one, nor is it intended to. The purpose of Sierra Club's proposal is to provide a glide path to avoided cost compensation. E3's results also do not account for overall NEM program savings achieved by moving existing NEM customers to electrification rates. The Commission should not rely upon E3's estimated payback periods because, as several parties have noted, they use NREL's ATB for system costs, which is substantially below actual data on installed costs due to its exclusion of costs such as developer profits, developer fees, and financing fees.[140] However, Sierra Club recognizes these results show payback periods in SDG&E service territory below four years, which can be corrected by setting the initial tranche of export compensation under Sierra Club's proposed glidepath at a step or two below electrification rates.

2. The Successor Tariff should be implemented no later than January 1, 2023

The successor tariff should be implemented by no later than January 1, 2023. To the extent utility billing systems have not been finalized by that time, a successor tariff customer could take service under NEM 2.0 terms with the understanding that they would move to the successor tariff once billing is finalized. To ensure consumer protection, suppliers of customer-sited generation would be required to inform potential customers of the anticipated timing of the transition to the successor tariff and provide bill savings estimates under the successor tariff. To make this possible, the Commission should provide public notice a reasonable time in advance of the adoption date. In the same vein, the Commission should not put the successor tariff into effect immediately upon adopting its Final Decision, to provide a grace period for prospective customers and solar providers to understand and adapt to the new structure.

[140] *See, e.g.*, Exh. ASO-01, Direct Testimony of A. Gong at 5:3–9.

E. Scoping Memo Issue 6: Other issues that may arise related to current net energy metering tariffs and subtariffs, which include but are not limited to the virtual net energy metering tariffs, net energy metering aggregation tariff, the Renewable Energy Self-Generation Bill Credit Transfer program, and the net energy metering fuel cell tariff.

1. As Agreed Upon by Multiple Parties to this Proceeding, the Commission Should Transition Existing NEM Customers to Electrification Friendly Rates.

Sierra Club had initially proposed the Commission transition existing NEM customers to electrification rates, defined as a rate with at least a 2:1 summer weekday POP ratio, at eight years from interconnection.[141] Sierra Club has conferred with NRDC, Cal Advocates, TURN, Coalition of California Utility Employees, CalWEA, and Independent Energy Producers Association and now recommends that the Commission transition existing NEM customers to electrification rates at five years from interconnection, and provide a storage rebate starting at $0.20/Wh (approximately $3,200 for an average residential system) to NEM 2.0 customers in exchange for switching to the end state of the successor tariff. Sierra Club agrees with this language in Section 5 Part 1 of the Joint Recommendations, with one modification: the exemption from transitioning to electrification rates should be expanded from CARE/FERA customers to all low-income customers, defined as households at or below 80 percent advanced metering infrastructure ("AMI"). The transition to electrification rates reduces customer bill savings if customers do not or cannot respond to TOU pricing signals, and low-income customers may be less able to adopt electrification technologies. Additionally, the relative impact of reductions in bill savings is higher for low-income customers. Identifying low-income households as those with incomes at or below 80 percent AMI more accurately reflects the cost of living in California and would provide critical customer protections to a very vulnerable customer segment.

At least three months prior to switching to the electrification rate, the IOU will perform a marketing and outreach campaign that shall include information on technologies and available incentives that can improve system value such as heat pump water and space heaters, electric vehicles, and batteries. In addition to potential operational cost savings from electrification and load shifting technologies, materials shall also explain the climate benefits of electrification and

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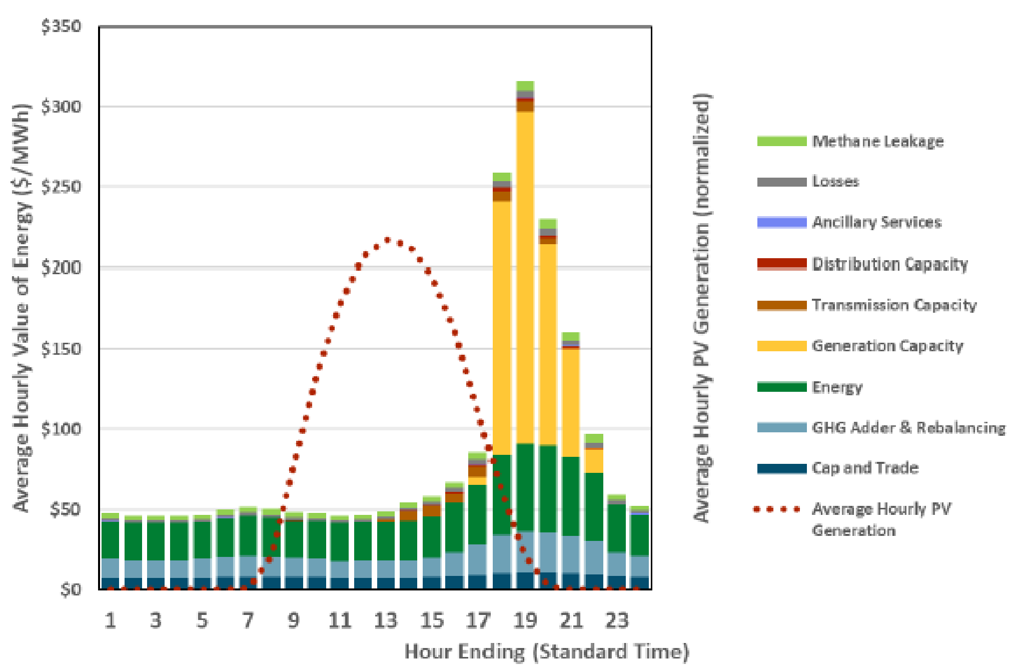
[141] Exh. SCL-01, Direct Testimony of M. Vespa at 6–22.

how utilizing energy during periods of mid-day solar generation and limiting evening usage reduces climate and air pollution. The transition to electrification rates would commence starting on January 1, 2023 for all systems interconnected in 2017 or earlier. Eligible rates for PG&E customers shall include EV2 and E-ELEC (if adopted in PG&E's Phase 2 GRC), TOU-D-PRIME for SCE customers and DR-SES or EV-TOU/EV-TOU2 for SDG&E customers until such time as SDG&E adopts a TOU rate with at least a 2:1 differential between summer weekday peak and weekday off-peak periods.

Transitioning existing NEM customers to electrification rates advances multiple objectives. First, as described more fully above in Section II.C.1.a, the cost-based nature of electrification rates reduces non-participant impacts and thereby furthers equity among customers, furthering Guiding Principle (b). As illustrated in the figure below of the Successor Tariff White Paper, in awarding the same or slightly lower export compensation for mid-day solar, the tiered and mildly differentiated TOU rates many NEM customers currently subscribe to fail to reflect the steep difference in value between mid-day and evening generation.[142]

Figure 4. 2020 Hourly Average Avoided Costs and Solar Generation, Annual Averages



Moving existing non-low-income NEM customers to more differentiated TOU rates is a

[142] Successor Tariff White Paper at 12.

necessary, cost-based realignment that communicates much more accurate price signals to existing NEM customers.

Second, as described more fully above in Section II.C.1.b, electrification rates discourage energy use during peak periods when carbon intensity and demands on the grid are highest, furthering Guiding Principle (g). These price signals need to begin to be imposed now, starting with NEM 1.0 customers, the majority of whom are on tiered rates and are therefore not discouraged from using energy during high GHG periods. It is not enough to wait for existing NEM customers to potentially opt into an electrification-friendly rate in the event they electrify and determine this rate to be financially advantageous. The climate crisis demands immediate and rapid GHG reductions and an end to fossil fuel reliance. As California continues to experience resource shortfalls and resorts to procurement of fossil-fueled backup generation, the Commission can discourage usage during high GHG periods when system reliability is most stressed by affirmatively moving existing NEM customers to electrification rates.

Third, as described more fully above in Section II.C.1.c, transitioning existing NEM customers to electrification rates encourages adoption of building and transportation electrification technologies. The analysis of Sierra Club Witness Dr. Camp demonstrates that rate schedules "E-ELEC, EV2, and TOU-D PRIME provide incentive for solar NEM customers to electrify their homes and vehicles."[143] For example, under Dr. Camp's analysis, with electrification of gas appliances and vehicles, a NEM 1.0 customer in Fresno that moved to E-ELEC would have annual bill savings of $754 relative to their prior tiered rate.[144] Not only does moving existing NEM customers to electrification rates continue to preserve substantial bill savings, but those that subsequently electrify will see overall bill savings relative to their former tiered rate or default TOU rate from avoided fuel costs from operation of fossil-fueled appliances and vehicles.[145] Moreover, solar customers that electrify their appliances and vehicles would reduce household GHG pollution by 59 to 78 percent.[146] Pursuant to Guiding Principle (e), moving existing customers to electrification rates incentivizes this urgently needed outcome.

Finally, Sierra Club strongly believes that an essential element of the successor tariff is a

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[143] Exh. SCL-02, Direct Testimony of Dr. Camp at 3:17–19.
[144] *Id.* at 16–17.
[145] *Id.* at 19–23.
[146] *Id.* at 3:15–16; 4:3–6.

glide path to export compensation at avoided cost to ensure the stable levels of rooftop solar deployment necessary to achieve California's decarbonization objectives. At the same time, Sierra Club does not believe the costs of the glide path should be fully borne by non-participants to the NEM program. Moving existing NEM customers to electrification rates offsets the costs of the successor tariff glidepath and does so in a manner that advances California's electrification efforts and incentivizes actions that result in substantial reduction in household climate pollution.

2. Moving existing NEM customers to a different rate structure is consistent with Commission precedent and reasonable customer expectation.

Both the NEM 1.0 and NEM 2.0 tariffs are overlays, meaning that the structure of the NEM program applies on top of whatever the customer's otherwise applicable tariff would be.[147] Past Commission decisions have determined that both NEM 1.0 and NEM 2.0 customers are guaranteed the option to remain on NEM until 20 years after their date of interconnection, while also making clear that the 20-year "transition period" for existing NEM customers guarantees only a continuing right to the NEM overlay on their rates, not to any particular underlying rate or rate structure.[148] Not only are changes to the underlying rates and rate structures through which NEM customers take service permitted, but the Commission has repeatedly signaled changes to rates should be expected.

First, in D.14-03-041, which established the 20-year transition period for NEM 1.0 customers, the Commission acknowledged that changes to residential rate design were "expected to result in significant changes to the residential rate structure, which may reduce the monthly savings from NEM,"[149] and noted that any forecasts by utilities about payback periods were fundamentally limited because they "cannot account for future changes to the actual electric rates

[147] D.15-07-001, *Decision on Residential Rate Reform for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company and Transition to Time-Of-Use Rates*, at 149, 154 (July 13, 2015) ("D.15-07-001"), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M153/K110/153110321.PDF.

[148] D.14-03-041, *Decision Establishing a Transition Period Pursuant to Assembly Bill 327 for Customers Enrolled in Net Energy Metering Tariffs*, at 18–20 (Apr. 4, 2014) ("D. 14-03-041") (holding NEM 1.0 customers have a right to stay on NEM 1.0 for 20 years from their individual interconnection date), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M089/K386/89386131.PDF; D.15-07-001 at 154–155; D.16-01-044 at 100–101 (holding that NEM 2.0 customers also have a right to stay on NEM 2.0 for 20 years from their interconnection date).

[149] D.14-03-041 at 19 (internal citation omitted).

underlying the NEM structure."[150] Then, in D.15-07-001, a decision implementing broad residential rate reform and structuring the transition to default TOU rates for residential customers, the Commission rejected the argument that "because the residential rate tariffs and the NEM tariff work jointly to determine a customer's bill, the Commission should require the utilities to retain all existing TOU rate schedules."[151] Instead, the Commission determined "contentions regarding customers' reliance on existing rates and rate structures to be unreasonable," and reiterated that there was no right for NEM customers to retain their underlying rate structure.[152] Then, in D.16-01-044, the Decision adopting NEM 2.0, the Commission again stated:

> To avoid any misunderstanding, we reiterate our observation in D.15-07-001 that [NEM] customers do not have any entitlement to the continuation of any particular underlying rate design, or particular rates. The 20-year period we designate applies only to a customer-generator's ability to continue service under the NEM successor tariff established by this decision.[153]

Accordingly, while Commission decisions have stated that existing NEM customers have the right to retail rate compensation for exports for twenty years, the retail rates themselves are subject to change. As the Commission has observed, "rates and rate structures change periodically, mostly gradually, through periodic revenue requirement and revenue allocation proceedings, but occasionally abruptly."[154] To mitigate the impact of changing rate structures for existing NEM customers, the Commission has allowed customers to remain on their existing rates for at least five years.[155] Ensuring a NEM customer can stay on their existing rate for five years is the balance the Commission has struck between moving to rates that better align with grid conditions and avoiding abrupt impacts to provide greater certainty to NEM customers.[156] Changing the underlying rate structure to which NEM customers subscribe – provided that any such change occurs after five years of a customer subscribing to NEM – is in keeping with

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[150] *Id.* at 18–19.
[151] D.15-07-001 at 150.
[152] *Id.* at 154.
[153] D.16-01-044 at 100–101.
[154] D.15-07-001 at 155.
[155] *Id.* ("Given the number of significant changes we are adopting, including tier flattening and increased use of minimum bills, and given the need for customer acceptance, we also find that the transition period for PG&E's E-6 tariff and SDG&E's DR-TOU tariff should be at least five years.").
[156] D.16-01-044 at 93–94.

Commission precedent.

Indeed, in D.17-01-006, the Commission determined that "[u]nreasonably long grandfathering periods prolong the period during which such customers receive less accurate and less cost-based TOU pricing signals."[157] The problem with extended legacy treatment of particular rate structures is even more acute in the case of NEM 1.0 customers, who are currently permitted to subscribe to tiered rates. These rates have no price signal to encourage on-site usage of generated energy, load shifting or reduced energy use during peak periods. While existing NEM customers have historically had the option to choose among available rates for which they qualify, any suggestion that existing NEM customers have a right to remain enrolled in specific rates or rate designs for the entire 20-year duration under which they are subscribed to NEM is the type of unreasonably long legacy period the Commission was concerned with in D.17-01-066 and to which there is no reasonable expectation. As the solar industry participants testified in this proceeding, "NEM2 customers who have installed their systems in recent years are getting much shorter paybacks on the order of 5 or 6 years."[158] Under this proposal, existing NEM customers would be moved to a cost-based rate after five years but continue to receive retail rate compensation for export under NEM for an additional 15 years. The proposed transition to a more cost-based TOU rate is a reasonable adjustment that is fully in keeping with Commission precedent and maintains significant system value for existing NEM customers.

III. CONCLUSION

For the reasons set forth above, Sierra Club respectfully requests the Commission adopt the four elements of Sierra Club's successor tariff proposal and move existing non-low-income NEM customers to electrification rates five years from interconnection.

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Respectfully submitted,

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[157] D.17-01-006 at 73 (Findings of Fact # 30).
[158] Tr. Vol. 8 at 1413:25–28 (T. Beach, SEIA/Vote Solar).

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